STATE OF MICHIGAN

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-17735

At the November 19, 2015 meeting of the Michigan Public Service Commission in Lansing, Michigan.

PRESENT: Hon. John D. Quackenbush, Chairman
Hon. Sally A. Talberg, Commissioner
Hon. Norman J. Saari, Commissioner

ORDER

I. HISTORY OF PROCEEDINGS

On December 5, 2014, Consumers Energy Company (Consumers) filed an application seeking authority to increase rates charged to its 1.8 million retail electric customers for the generation and distribution of electricity, and for other regulatory approvals. The rate increase sought in this proceeding is based on the company's projections for relevant items of investment, expenses, and revenues for a test year covering the 12-month period from June 1, 2015 to May 31, 2016. Consumers averred that, without rate relief, the utility will experience a jurisdictional electric revenue shortfall of $166 million on an annual basis during the test year. The utility also stressed that the $166 million shortfall does not include the additional $35 million revenue deficiency associated with its purchase of a 540 megawatt (MW) combined cycle natural gas generating facility located in Jackson, Michigan (Jackson Plant), or the revenue sufficiency related to the reduction of $38 million of operation and maintenance (O&M) costs associated with Consumers' expected retirement of seven small coal-fired generation units.[1] Netting the revenue impacts of the $166 million test year deficiency, the $35 million revenue requirement associated with the Jackson Plant acquisition, and the annual O&M savings of $38 million associated with closure of the Classic 7, brings the annual test year revenue deficiency to $163 million.

Consumers explained that the acquisition of the 540 MW Jackson Plant would only partially offset the 956 MW capacity reduction associated with closure of the Classic 7 plants. Consumers contended that additional capital expenditures for environmental, legal, and safety-related investments in electric utility generation and distribution assets were required. Consumers also asserted that technological improvements, such as its advanced metering infrastructure (AMI) project, were reasonable and necessary. Indeed, Consumers asserts that approximately $211 million, or 130% of its rate request, is comprised of investment-related costs that are part of the company's five-year capital investment plan. Further, Consumers claimed that additional O&M expenditures were necessary to improve the reliability of service to its customers.

Consumers conceded that its need for additional revenues to fund all of the aforementioned activities had "been offset, in part, by $132 million of reductions including the MPSC-approved accelerated amortization of cost of removal income tax benefits due customers, reductions in employee benefit expenses, and removal of the operating costs" of the Classic 7. Application, pp. 3-4. According to Consumers, the net impact of all matters to be considered in this proceeding supports the company's request for rate relief of $163 million. Consumers maintains that absent rate relief in this amount, the utility will experience revenues so low as to deprive it of a reasonable return on its investments in violation of the federal and state constitutions.

[1] These seven generating units are Cobb Units 4 and 5, Weadock Units 7 and 8, and Whiting Units 1, 2, and 3. They are referred to throughout this order as the "Classic 7."

Consumers proposed that rates established in this case include an authorized rate of return on common equity (ROE) of 10.7%, and reflect an overall rate of return on total rate base of 6.5%. Consumers stated that its application relies upon the depreciation rates established in Case No. U-16054, but stressed that if a final order has been issued in its pending depreciation proceeding, Case No. U-17653, the newer depreciation rates established in that case should be used.[2]

Consumers proposed in its application that the rate increase be implemented in the following "three step" manner:

1. At the conclusion of the proceeding, Consumers' base rates would be increased by $201 million.
2. Simultaneous with the implementation of the $201 million rate increase, Consumers would be authorized to immediately apply a credit to customers' bills to reduce Consumers' recovery by $35 million (the revenue requirement associated with the 540 MW Jackson Plant) that would remain in effect until the Jackson Plant purchase closes and the plant becomes fully operational, at which point the credit would be terminated.
3. Upon retirement of the Classic 7 plants in April 2016, Consumers' rates would be adjusted downward by $38 million to reflect the decrease in O&M associated with the operation of those plants.

In addition to the "three step" process for implementation of its proposed test year rate increase, Consumers is also requesting approval of two novel revenue adjustment mechanisms designed to allow the utility "to address certain volatile and hard-to-predict cost of service elements."

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[2] The Commission's May 14, 2015 order in Case No. U-17653 (May 14 order) approved new depreciation rates. Consumers states that the new depreciation rates resulted in approximately $33.5 million in additional depreciation expense, increasing its request for final rate relief to $198.6 million.

Application, p. 6. The first such mechanism proposed by Consumers is an "Investment Recovery Mechanism" (IRM). Consumers explains that its projected average rate base for the test year ending May 31, 2016, is approximately $9.2 billion, excluding the Jackson Plant. According to Consumers, the utility is projecting to make approximately $1.4 billion of additional investments in 2017, and another $0.8 billion in 2018. Capital expenditures in these amounts for 2017 and 2018 are expected by Consumers to increase average net plant by $0.9 billion and $0.5 billion in 2017 and 2018, respectively. Consumers anticipates that these capital expenditures will cause the company to experience an incremental revenue deficiency of $163 million in 2017 above the levels reflected in its test year rates, and by an additional $78 million in 2018. Denial of the IRM, says Consumers, will significantly contribute to the utility's need to file frequent rate cases.

The second mechanism proposed by Consumers is a "Revenue Adjustment Mechanism" (RAM), which the utility recognizes would violate current state law. As such, the utility asks that the Commission only "conditionally" approve this request. The condition for implementation of the RAM would be approval by the Legislature and the Governor of new legislation authorizing its use during the pendency of the instant case.

In addition to rate relief, Consumers proposed a variety of revisions to its electric rules, regulations, and tariffs, generally described in paragraph 16 of its application. Consumers also stressed that its cost of service study (COSS) and proposed rate design were consistent with its proposals in Case No. U-17688, which was conducted in response to passage of Act 169 of 2014; MCL 460.11 (Act 169). According to Consumers, the rate design proposals in Case No. U-17688 and in this case "will result in more competitive rates for energy-intensive customers, while keeping residential bills affordable." Application, p. 9. Finally, in paragraphs 18 and 19 of its application, Consumers requested approval of various forms of accounting authority.

A prehearing conference was held before Administrative Law Judge Mark E. Cummins (ALJ) on January 14, 2015. At the prehearing conference, the ALJ granted petitions to intervene filed by the Michigan Department of the Attorney General (Attorney General), the Association of Businesses Advocating Tariff Equity (ABATE), the Michigan State Utility Workers Council, Utility Workers Union of America, AFL-CIO, The Kroger Company (Kroger), Michigan Environmental Council and Natural Resources Defense Council (MEC/NRDC), Hemlock Semiconductor Corporation (Hemlock), Energy Michigan, Michigan Cable Telecommunications Association, the Midland Cogeneration Venture Limited Partnership (MCV), and Michelle Rison and the Residential Customer Group (together, RCG). The Commission Staff (Staff) also participated. Because a representative of intervenors Wal-Mart Stores East, LP, and Sam's East, Inc. (together, Wal-Mart) did not attend the January 14, 2015, prehearing conference, the ALJ took the matter of their petition to intervene under advisement. Thereafter, the ALJ approved a schedule for the remainder of the proceedings that was agreed to by the parties in attendance.

On February 3, 2015, the ALJ conducted a second prehearing conference at which he granted the timely petition to intervene previously filed by Wal-Mart, as well as a late petition to intervene that was submitted by the Municipal Coalition.

On May 14, 2015, Consumers filed the testimony of one witness and two exhibits in support of self-implementation of a $110 million rate increase on and after June 4, 2015. Consumers proposed to increase annual revenues by $110 million through use of equal percentage increases to all retail rates. Consumers also indicated in that filing that the company intended to increase its annual revenues by another $56 million effective June 4, 2015, through elimination of the Power Plant Bill Credit that the utility had been ordered to include on its customers' bills as a result of the December 3, 2013 approval of the utility's securitization application in Case No. U-17473.

On May 18, 2015, the ALJ conducted a hearing on the company's proposed self-implementation. Only Consumers and the Staff presented evidence. Neither of the two witnesses was subject to cross-examination. On May 26, 2015, Consumers filed a brief in support of its self-implementation request. Absent action by the Commission, on June 4, 2015, Consumers self-implemented a rate increase designed to produce additional annual retail electric revenues of $110 million above levels established by the May 15, 2013 order in Case No. U-17087. The utility also eliminated the Power Plant Bill Credit which, when combined with self-implementation, had the effect of increasing Consumers' retail rates by a total of $166 million on an annual basis as of June 4, 2015.

The evidentiary phase of the proceedings commenced on June 10, 2015, and continued through June 15, 2015. On July 17, 2015, briefs were filed by Consumers, the Staff, the Attorney General, ABATE, Kroger, MEC/NRDC, the Municipal Coalition, Hemlock, Energy Michigan, RCG, and Wal-Mart. On August 7, 2015, reply briefs were filed by the same parties, with the exception of Energy Michigan.

On September 16, 2015, the ALJ issued his Proposal for Decision (PFD). Exceptions to the PFD were filed by the Municipal Coalition on October 8, 2015, and by Hemlock, MEC/NRDC, ABATE, the Staff, Consumers, the Attorney General, and the RCG on October 9, 2015. Replies to the exceptions were filed by MEC/NRDC, Hemlock, the Staff, ABATE, the Municipal Coalition, Consumers, the Attorney General, and the RCG on October 21, 2015. The record consists of 2,487 pages of transcript and 308 exhibits received into evidence.

II. <u>TEST YEAR</u>

Both Consumers and the Staff proposed using the 12-month period ending May 31, 2016, as the test year, and no party objected. Consumers began with historical data from calendar year

2013, which was then adjusted to reflect updated sales and projections of investment, expenses, and revenues. The ALJ recommended adopting this test year, and the Commission agrees.

III. <u>RATE BASE</u>

Rate base consists of total utility plant (i.e., the capital invested in all plant in service, plant held for future use, and construction work in progress (CWIP)), less the company's depreciation reserve (consisting of its accumulated depreciation, amortization, and depletion), plus the utility's working capital requirements. Consumers proposed setting its total rate base for the test year at $9,284,326,000, consisting of $8,548,573,000 in net plant and $764,495,000 in working capital, less $28,743,000 in retainers and customer advances. Consumers contended that most of the increase in its proposed rate base over existing levels is related to anticipated capital expenditures in such areas as distribution and energy supply systems, fossil and hydroelectric generation facilities, information technology upgrades, and AMI hardware.

A. Net Utility Plant

1. Capital Expenditures on Fossil- and Hydro-Based Generation

a. Air Pollution Control Contingency Amounts

The first amount disputed under net utility plant concerns projected air quality control systems (AQCS) contingency costs of $26,804,000 for 2015 and $10,674,000 for the first five months of 2016, for a total of $37,487,000. Exhibit S-10.1. David F. Ronk, Jr., Consumers' Director for Electric Transactions and Wholesale Settlements, testified as to the utility's plan to retrofit a handful of its coal-fired generating units, retire the Classic 7, and acquire the gas-fired Jackson Plant, based upon its need to satisfy the U.S. Environmental Protection Agency's (EPA) Mercury and Air Toxics Standards (MATS rules). David B. Kehoe, Consumers' Director of Staff, Electric Generation, testified with regard to expenditures that will be needed to remain in compliance with environmental requirements, as did Linda M. Hilbert, Consumers' Manager of Environmental Services.

Nicholas M. Evans, a Public Utilities Engineer in the Generation and Certificate of Need Section of the Commission's Electric Reliability Division, testified on behalf of the Staff. The Staff argued that the entire AQCS contingency amount should be disallowed, resulting in a reduction of $24,360,000 to rate base. Mr. Evans testified that it is inappropriate for the utility to recover a return of and on projected contingency expenditures that may not be incurred at all, or may be incurred in significantly reduced amounts. He further testified that allowing contingency expenditures in rate base may dampen the utility's incentive to control costs. Mr. Evans testified that a range of possible spending, as opposed to a target, creates a much higher degree of uncertainty than is found in other cost categories. 8 Tr 1615. The Staff further argued that recovery of reasonable and prudent air-quality control expenses may still take place in the next rate case, where they will not be presented as contingencies. MEC/NRDC and the Attorney General supported the Staff's position.

Consumers countered that well-established and industry-accepted project management standards routinely provide for the inclusion of contingency costs, and that the Staff failed to prove that the projected costs are unreasonable. Consumers argued that Mr. Kehoe provided testimony regarding the "blackbox process" that supports the utility's proposal. Mr. Kehoe testified that the blackbox process "recognizes that individual project contingency dollars, when combined, may represent more contingency dollars than are required." 6 Tr 720. He further testified that "Contingencies that are determined to have a high degree of probability or risk are left in the project estimate, while contingencies that are found to have a lower probability or risk are credited to the Blackbox. . . . If the Commission were to adopt Staff's recommendation to remove contingency expenditures, those expenditures would be removed twice – resulting in a significant under-funding for these critical and costly pieces of equipment." 6 Tr 721.

The ALJ agreed with the Staff that the AQCS contingency amounts should be removed from net utility plant. The ALJ found that rate recovery and project management are not the same thing. He noted that the Michigan Court of Appeals recently held in *In re Application of Indiana Michigan Power Company for a Certificate of Necessity*, 307 Mich App 272, 296; 859 NW2d 253 (2014) that recovery of contingency funds related to the renovation of a Michigan nuclear generation facility should be denied where it was not clear, by substantial evidence on the whole record, that those expenditures would be reasonable. Further, the ALJ found that none of Consumers' witnesses were able to provide specific details for any of the projects connected with the contingency amounts. The ALJ pointed out that, if approved, the utility would be allowed to earn a return on any AQCS contingency projections and that return would remain with the utility regardless of whether the expenditure ever took place. Finally, the ALJ stated that the blackbox, as described by Consumers, is not an acceptable mechanism for addressing contingencies such as those described here. He found that the record contains conflicting descriptions of how the blackbox is calculated, and that there is simply too much uncertainty associated with the contingency amounts. The ALJ recommended that the Commission disallow the AQCS contingency amounts, and reduce Consumers' projected test year rate base by $24,360,000.

In its exceptions, Consumers argues that standard project management practices overwhelmingly support the use of contingency costs. Consumers further argues that the *Indiana Michigan* case has no relevance to this proceeding because it involves the interpretation of MCL 460.6s, and not MCL 460.6a. Consumers points out that the statute governing the certificate of need contains language that appears to provide for a 10% contingency provision, and argues that the court's determination relates to this specific language, as well as the specific facts of that case. *See*, MCL 460.6s(9).

Consumers further argues that the ALJ fails to perceive that contingency costs are real costs, and are a reasonable and prudent component of total costs. The utility argues that contingency costs are project-specific, specifically-analyzed and projected cost amounts similar to any other budget item. 7 Tr 1259-1260. Consumers contends that the Commission has previously confirmed the validity of contingency costs in the May 7, 1991 order in Case No. U-9493, p. 14, and the March 3, 2000 order in Case No. U-11724, p. 14. Consumers maintains that the Staff recommended the inclusion of projected AQCS contingency costs in rate base in Case No. U-17087 (Consumers' previous rate case), and that no party has shown that Consumers will not incur the disputed costs. Finally, Consumers argues that the blackbox process eliminates costs in the aggregate and removes contingencies that have a low probability of risk.

In reply, the Staff reiterates that its position is based on sound ratemaking principles and not on project management budgeting practices. The Staff points to the testimony of Ms. Hilbert indicating that "individual project contingency dollars when combined may represent more contingency dollars than are ultimately required." 7 Tr 1261. The Staff also notes that Case No. U-17087 was settled and that the Staff never took a position on AQCS contingency costs in that matter.

MEC/NRDC also argue on reply that the ALJ analyzed this issue correctly, noting that the contingency costs are about 15% of the total projected costs. MEC/NRDC contend that the proffered project-specific analyses were not competent evidence and that no witness could explain them. MEC/NRDC note that the two previous Commission cases cited by Consumers in its exceptions were depreciation cases that involved the issue of the inclusion of contingency amounts in future removal costs to be incurred decades down the road. MEC/NRDC contend that Consumers' witnesses gave conflicting accounts of how the blackbox works, and never explained which projects had their contingency expenses added to the blackbox and which had the amount left in the total estimated cost.

By definition, contingency amounts are amounts set aside for cost items whose occurrence is uncertain. The Commission agrees with the Staff and the ALJ that inclusion of such items in rate base is not sound ratemaking practice, particularly where the utility failed to convincingly explain how the contingency amounts were arrived at, or even specify which projects had contingency amounts that were credited to the blackbox. Ms. Hilbert testified that each contingency amount "is a risk-based estimated monetary value" that is based on a "quantitative analysis of the project's risks and opportunities," and that the values "reflect a probabilistic approach tailored to the project," generated by "the probability of occurrence multiplied by the potential impact," subject to periodic review. 7 Tr 1260; Exhibits A-95 and A-96. The emphasis is clearly on probabilities. Support for the amounts themselves is claimed to be in Exhibit MEC-37, but none of the dollar values in that exhibit correspond to the contingency amounts on Exhibits A-95 and 96. As the ALJ noted, neither Mr. Kehoe nor Ms. Hilbert could describe how the amounts were derived. The record is simply inadequate to allow the Commission to conclude that these contingency amounts rise to the level of cost items that appropriately belong in rate base earning a return of and on the "investment."

The Commission finds that $37.5 million in contingency funds in this category should be excluded from capital expenditure. As MEC/NRDC point out, Consumers is not precluded from seeking recovery of any amounts actually incurred in a future rate proceeding.

b. Projected Steam Electric Effluent Guideline Expenditures

Consumers proposed projected capital expenditures associated with compliance with the EPA's (then) proposed steam electric effluent guidelines (SEEG) of $7,062,000 for 2015 and $5,549,000 for the first five months of 2016, for a total of approximately $12.6 million.[3] The EPA was expected to finalize the SEEG by September 30, 2015. The proposed expenditures are associated with the commencement of studies, as well as the engineering and design of new dry bottom ash systems and wastewater treatment systems.

The Staff opposed the inclusion of this cost, on grounds that it is premature for the utility to commence studies and other work associated with SEEG compliance before the final rule is actually issued. MEC/NRDC supported the Staff. Consumers countered that it is necessary to conduct a technology feasibility study and a wastewater study prior to developing the least-cost method of complying with the SEEG on time.

The ALJ recommended that this cost item be included in net utility plant. The ALJ found that taking immediate steps to ensure compliance with the final SEEG is not only reasonable and prudent but also imperative, because the SEEG will have an impact on the next National Pollution Discharge Elimination System (NPDES) permit cycle in early 2016. PFD, p. 25; 7 Tr 1263.

In its exceptions, the Staff notes that the SEEG rule was finalized on September 30, 2015, but continues to recommend that the Commission defer recovery of these projected expenditures until a future rate case. The Staff states that it has not had time to review the final rule, or to compare the utility's cost projections with the precise requirements of the new rule. The Staff posits that in

[3] Consumers also proposed inclusion of SEEG-related costs for 2016 and 2017 through the operation of its proposed IRM. The discussion of the fate of this proposal, and all other such proposals related to net utility plant and the IRM, is in the section of this order that addresses the IRM request.

its next rate case Consumers will have actual compliance costs and more refined cost estimates for the Commission to consider.

In reply, Consumers contends that the final SEEG rule contains Option 4a (the compliance option upon which Consumers' projected investments are based), and is even more demanding than the proposed rule, meaning that even greater investments may be required for compliance.

The Commission agrees with the ALJ and Consumers that a wait and see approach is inappropriate. In any case, the wait is over. The final SEEG rule was promulgated on September 30, 2015, and it would have been inappropriate for the utility to do nothing by way of planning until actual promulgation, given the immediate effect on the NPDES permitting cycle and the fact that Consumers' renewal application is due in early 2016, which no party disputed. 7 Tr 1262; *see,* http://www2.epa.gov/eg/steam-electric-power-generating-effluent-guidelines. The Commission approves the requested $12.6 million for this expenditure category.

2. Capital Expenditures for Distribution and Energy Supply

Mary P. Palkovich, Consumers' Vice-President of Energy Delivery, testified that the utility requests rate recovery of $1,373,586,000 for both past and projected capital expenditures for electric distribution related facilities spanning the period of 2013 through the first five months of 2016. Within this cost category, three areas of dispute arose.

a. Demand Failure Program Investments

Consumers requested recovery of approximately $140 million in the demand failure program cost category, which includes costs associated with customer outage restoration and the repair or replacement of equipment, including pole tops, due to unanticipated or imminent failures. This amount reflects an increase of about $27 million over the 2013 historical test year amount.

The Staff argued in favor of approximately $103 million for the demand failure program. This amount is based upon the five-year historical average of investment made by Consumers in demand failure projects, according to the Staff's witness Ryan Laruwe, an Engineer in the Electric Operations Section of the Commission's Operations and Wholesale Markets Division. The Staff argued that Consumers' figure was overly influenced by the effect of the historic test year, 2013, in which Michigan was hit by a major ice storm and the effects of the polar vortex. The Attorney General supported $125 million for this program.

The ALJ found that the full amount proposed by Consumers should be included in net utility plant. He opined that the effects of the ice storm did not greatly alter the utility's capital expenditures, because service restoration costs constitute O&M expenses and not capital expenditures. The ALJ noted that Consumers' demand failure expenditures did not significantly increase in 2013, and found that the utility adequately supported its expenditure request. The ALJ recommended that the Commission adopt the $140 million figure for this program requested by the utility.

In exceptions, the Staff points to Consumers' evidence showing that a portion of the capital expenditures in this category is associated with outage restoration and repair. 8 Tr 1338-1339. The Staff argues that, subtracting known and measurable expenditures in this category based upon Ms. Palkovich's testimony, outage restoration and repair accounts for 72% of the test year budget. Thus, the Staff argues, the 2013 storms clearly had an effect in this capital category. Additionally, the Staff argues that Consumers only estimates its pole top rehabilitation costs, and that estimation should not be necessary because this expense exists in O&M. *See,* 8 Tr 1317. The Staff contends that the record lacks support for this estimate, and for the $31.5 million sought in capitalization costs. The Staff points out that disallowing these estimated costs will not foreclose eventual recovery of reasonable and prudent amounts in a future rate case. The Staff supports approximately $103 million in capital expenditures in the demand failure category.

In reply, Consumers contends that the demand failure proposal is related to outage restoration and repair, but is not directly affected by weather. The company does not disagree with the Staff's point that much of this expense is related to outage restoration and repair, but contends that it is expended no matter what the weather. Consumers further argues that the Staff provided no evidentiary basis for critiquing the utility's projections regarding pole-top maintenance.

The Commission agrees with the ALJ and finds that $140 million should be authorized for this cost category. Consumers is correct that customer outage restoration and repair costs will be incurred every year, weather aside, and the Commission finds that the testimony of Ms. Palkovich adequately supported the capitalization of the pole-top rehabilitation program, which includes overhead costs such as pension, payroll, engineering, and supervision. 8 Tr 1317, 1357.

b. Capacity Related Expenditures

Consumers requested recovery of approximately $58.6 million in capacity related capital expenditures that consist primarily of capital investments necessary to ensure that the utility's high voltage demand (HVD) electric system is capable of serving forecasted peak demand for all HVD facilities, that HVD facilities can be taken out of service for maintenance and construction, and that low voltage distribution (LVD) system overloads can be fixed. Ms. Palkovich testified that, as a result of Consumers' capacity related expenditure program, no significant customer service related issues occurred when the utility's system experienced its all-time highest gross peak load in July 2012. The amount sought by the utility is about $18.5 million above its 2013 historic test year level.

The Staff argued that this amount should be reduced to $52.5 million, and the Attorney General supported $52.2 million. The Staff again based its recommendation on the historical five-year average; and the Staff argued that Consumers' total system peak demand should drop somewhat over the next several years.

The ALJ recommended that the Commission include the full amount requested by the utility for this cost category, finding that it is closer to what can be expected during the projected test year than the Staff's number. The ALJ noted that Consumers' historical eight-year spending average for capacity related projects is approximately $61.4 million, which is $3 million more than the utility is requesting. Exhibit A-113. He further noted that, according to Ms. Palkovich's testimony, the utility appears to have a backlog of capacity projects. The ALJ noted that capacity related expenditures may be associated with localized load growth, and are not necessarily related to the system as a whole. The ALJ recommended that the Commission adopt the $58.6 million figure for this cost category.

In exceptions, the Staff points out that the utility is requesting a 45% increase from the historic test year in this category. The Staff argues that, despite the increase, Consumers provided no information on capacity projects or modeling scenarios that verify that the targeted problems will arise at any greater frequency than they have in the past. Moreover, the Staff points out that Consumers provided evidence showing that the utility expects decreases in system peak demand through 2018. 10 Tr 1909. The Staff maintains that, although Consumers made claims about localized growth, the utility failed to add any support on the record in terms of time periods, costs, or loading data related to any local projects. The Staff maintains that these expenditures are unreasonable at this time, and that eventual recovery is not foreclosed if the Commission chooses to adopt the Staff's $6 million decrease.

In reply, Consumers argues that it has historically spent more than its projected expenditures for the capacity program, indicating that eight-year average spending is $61.4 million. 8 Tr 1358. The company again asserts that these expenses are not for the system as a whole but rather reflect localized needs, and that the company currently has a backlog of capacity projects.

The Commission agrees with the Staff that a 45% increase is significant, and that the utility failed to justify this increase in a time of declining system peak capacity, citing to only one local project – the Ellsworth substation. The Commission approves the $52.5 million capital expenditure amount proposed by the Staff.

c. New Business Facilities

Consumers requested recovery of approximately $60 million in new business capital expenditures, that consist primarily of investments relating to the addition of new residential, commercial, and industrial customers to its system. The amount sought by the utility is approximately $12 million above the 2013 historical test year level.

The Staff argued that this amount should be reduced to $55.5 million; and the Attorney General supported $38.5 million, which is 20% lower than the 2013 historical test year level. The Staff bases its figure on a two-year average, looking only at 2013 and 2014. The Staff argues that it is appropriate to focus only on recent growth, and that the utility is being overly optimistic about future growth.

The ALJ recommended that the Commission adopt the amount proposed by Consumers. The ALJ found that recent new business growth shows a trend toward more costly primary line extensions and the installation of LED streetlights. The ALJ found that Consumers sufficiently supported its proposed investment amount in Exhibit A-114. Finally, the ALJ noted that

Consumers is bound by tariffs that require the utility to provide services as long as the customer meets the tariffed requirements.

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

3. IT Capital Expenditures

Christopher J. Varvatos, an Executive Director in Consumers' Information Technology (IT) Department (formerly known as the Business Technology Solutions Department), testified that the utility seeks rate recovery of $217,670,000 for past and projected capital expenditures for IT facilities spanning the period of 2013 through the first five months of 2016. These expenditures primarily concern investments in software applications, asset management programs, and cybersecurity systems. The ALJ states that no party proposed a disallowance in this cost category. PFD, p. 36. However, the Staff proposed that the utility be required to provide the Staff with an annual report on the utility's cybersecurity program, in light of the constantly changing nature of this field. *See*, Exhibit S-14.0. Consumers agreed to the reporting requirement, and requested flexibility with regard to how the information is provided. The ALJ recommended that Consumers' projected IT capital expenditures of $217,670,000 should be adopted for use in this proceeding, and that the utility should provide the requested annual report according to the framework described in Exhibit S-14.0, with the flexibility to vary the means of delivering protected or confidential information.

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

4. AMI Capital Expenditures

Lincoln D. Warriner, a Senior Regulatory and Business Analyst in Consumers' Smart Energy Financials Department, testified with regard to Consumers' AMI program. He indicated that the installation of smart meters is expected to be completed sometime during 2017, and that the utility has established an opt out program that allows customers to use a non-communicating meter. Mr. Warriner testified that only 0.46% of the utility's customers are, thus far, electing to opt out.

As an initial matter, the ALJ addressed Consumers' request that the Commission accept the current meter installation schedule as the benchmark for future determinations regarding the temporary waiver of electric meter testing requirements during 2016 and 2017. PFD, p. 38, note 17; *see,* the September 26, 2014 order in Case No. U-17057. The Staff (the only party that responded) supported this request, and the ALJ recommended that the Commission accept the target of 754,693 AMI meter installations by the end of 2015 as the new benchmark for determining the status of the meter testing waiver for 2016 and 2017. No exceptions were filed on this issue. The Commission adopts the findings and recommendations of the ALJ on the new installation benchmark.

Addressing another preliminary matter, the ALJ examined Consumers' request that the Commission find that the utility no longer needs to submit a net present value-based cost/benefit analysis of the AMI program in future rate cases. PFD, p. 40, note 19. The Staff objected on grounds that this would conflict with the September 11, 2012 order in Case No. U-17000, p. 4. Based on the clear language of that order, the ALJ recommended that the Commission reject the utility's proposal.

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

a. Test Year AMI Expenditures

Mr. Warriner testified that Consumers' electric AMI capital expenditures for the projected test year are $76,709,000 for 2014, $104,249,000 for 2015, and $54,522,000 for the first five months of 2016, for a total of $235,480,000. Mr. Warriner testified that these amounts are consistent with AMI cost recovery amounts in prior years, beginning in 2009.

The Attorney General argued that the AMI program should be suspended because it is not economically justified. In the alternative, he argued that the Commission should defer recovery of depreciation expense for any AMI investment in rate base. The RCG supported the Attorney General's positions.

The Staff argued in favor of a reduction of $6,073,000 to remove all contingency-based costs. Lauren Fromm, a Public Utilities Engineer in the Smart Grid Section of the Commission's Electric Reliability Division, testified that Consumers actually spent $7,053,000 less on its AMI program than it projected it would during 2014. As with the AQCS contingency costs, the Staff indicated that the utility would have the potential to recover depreciation expense and a return on expenditures that may never occur, or may be significantly reduced.[4] Consumers agreed to the Staff's proposal. PFD, p. 48.

[4] In its AMI presentation, the Staff made four additional requests: (1) that Consumers be directed to continue participating in ongoing bi-monthly technical meetings with the Staff as long as AMI infrastructure installation continues; (2) prior to the initiation of any new AMI-related pilot, Consumers provide the Staff with a description of the scope of the pilot, its projected costs, and the goals and objectives to be accomplished by the pilot; (3) upon completion of any new pilot, Consumers provide results to the Staff including the pilot program's cost, all conclusions reached as a result of the pilot, and how the results will be utilized in the company's future AMI deployment; and (4) that Consumers include its new pilot program results in future rate case applications, as well as providing updates on such programs to the Staff during their bi-monthly technical meetings. No party objected to these requests and the ALJ recommended their adoption. PFD, p. 45, note 21; *see*,10 Tr 2093. No exceptions were filed. The Commission adopts the recommendation of the ALJ on these four Staff requests.

Citing numerous Commission orders so finding, the ALJ recommended rejecting the Attorney General's (and the RCG's) proposal to terminate the AMI program. Further, the ALJ found that the RCG had not presented convincing evidence to show that the benefits of AMI could effectively be replaced by renewable energy and energy efficiency measures, and customer activities like purchasing smart thermostats. The ALJ agreed with the Staff that, while renewable energy represents a source of supply and energy efficiency represents the opportunity to reduce supply, they are not a substitute for AMI deployment. PFD, pp. 48-49, note 22. The ALJ found that adequate cost/benefit information has been provided in this record to support continued funding of the AMI program. Finally, he found that the Attorney General's alternative argument regarding depreciation was largely based upon analogy to a decision by the Maryland Public Service Commission, and that this ruling was of little relevance to this proceeding. The ALJ recommended that the Commission reject the requests to terminate the AMI program or to change its depreciation related treatment. The ALJ recommended adoption of the full amount proposed by Consumers minus the contingency costs, for a total of $229,407,000 in test year expenditures.

The RCG filed an exception, arguing that the utility's cost/benefit analysis is unreliable. In its replies to exceptions, the RCG argued this issue more thoroughly in the form of stating that it agrees with the Attorney General's third exception regarding the AMI program. The RCG contends that Consumers' large rate request is mostly a result of the cost of the AMI program. The RCG maintains that the cost/benefit study was self-serving and subjective, and has no nexus to the cost of service formula used for ratemaking. The RCG asserts that the cost/benefit analysis should have included consideration of alternative strategies such as phasing in AMI more slowly, or investing in renewable energy and energy efficiency instead. The RCG urges the Commission to exclude from rate base the remaining amount associated with meter scrapping, or give it the alternative depreciation treatment proposed by the Attorney General.

In its replies to exceptions, Consumers contends that the Commission lacks the authority to terminate the AMI program, and that it has presented evidence sufficient to show that the benefits of the AMI program to customers exceed the costs.

The Commission adopts the findings and recommendations of the ALJ. As the ALJ relates, the Commission has thoroughly vetted the underlying cost/benefit analyses and the AMI program itself and will not revisit those issues. *See*, November 2, 2009 and October 7, 2014 orders in Case No. U-15645; November 4, 2010 order in Case No. U-16191; June 7, 2012 order in Case No. U-16794; and June 28, 2013 order in Case No. U-17087. The AMI program is correctly characterized as a grid modernization program that cannot be replaced by renewable energy or energy efficiency measures. The Commission finds that no party provided evidence showing that conditions have changed such that the current rate base and depreciation treatment of these expenses should be changed. Consumers shall continue to provide cost/benefit analyses as long as the program is still in the implementation phase. The Commission approves Consumers' proposed test year expenditure, minus the contingency expenditure identified by the Staff.

b. Direct Load Administration Switch Expenditures

Consumers requested recovery of projected expenditures relating to the installation of direct load administration (DLA) switches of $5.186 million through the test year. Exhibit A-74. The DLA switch program would provide incentives for customers to allow Consumers to directly control the operation of their air conditioning units during periods of high peak demand. The program was to begin in 2015, and would cover approximately 110,000 enrollees. Mr. Warriner testified that ZigBee-based DLA switches have been proven to successfully reduce demand on peak summer days. 6 Tr 966-967.

The Staff opposed any recovery in this cost category, arguing that the functionality of the switches has not been proven in a pilot, and that recent developments in direct load control made these switches potentially outdated.

The ALJ found that this cost category should be included in the full amount in net utility plant. The ALJ found that the Staff had not shown what demand reductions would be realized if the utility waited for future or alternative technology. The ALJ recommended that the Commission approve the level of investment sought by the utility, albeit for the test year only.

In exceptions, the Staff argues that Consumers is attempting to adopt an antiquated technology, and is ignoring current best practices across the industry. The Staff maintains that the DLA program will result in fewer benefits, less customer satisfaction, and higher costs for ratepayers than readily available alternatives. Moreover, the Staff contends that intelligent communicating thermostats (ICT) can outperform the proposed program, and that hard-wired switches do not provide any customer empowerment or customer education. Instead, the DLA program results in customers who are not aware of when load reduction occurs. The Staff maintains that ICTs are associated with greater energy efficiency benefits. At a minimum, the Staff argues, the Commission should postpone approval of the DLA program until Consumers concludes the ongoing Zigbee-based thermostat pilot program.

In reply, Consumers contends that customer empowerment and education are not goals associated with the DLA program. Consumers argues that the Staff failed to provide any analysis showing the peak demand reductions that could be realized from another technology, or what the cost would be. Consumers further points out that it is already investigating the use of ICTs, and that the specific thermostat used in its pilot program is not currently available to the mass market; and that even the Staff did not dispute the cost/benefit projections. 9 Tr 1926.

The Commission agrees with the ALJ and the company, and finds that these expenditures for the test period should be approved. DLA switches have been shown to be effective in reducing peak demand. 6 Tr 967. Simply because there are additional technologies available (and on the horizon) that will also be effective for reducing peak demand, such as ICTs, is not an argument for disallowing expense for a technology that can be implemented in short order for relatively little cost, and that can be expected, based on experience, to provide the benefits that Consumers described. The Commission approves $5.186 million for inclusion in capital expenditures for this cost category.

5. Construction Work in Progress

Consumers requests inclusion of approximately $976 million in CWIP in net utility plant for the test year. Wal-Mart objected to that request, arguing that CWIP should not be included in rate base because the assets have not yet been deemed used and useful. The ALJ recommended that the Commission reject Wal-Mart's proposal, finding that the Commission has long allowed utilities to include CWIP in rate base, going back to the May 10, 1976 order in Case No. U-4771, along with an allowance for funds used during construction (AFUDC) offset for longer term projects. The ALJ recommended that the Commission retain its traditional treatment of CWIP.

No party filed exceptions, and the Commission adopts the findings and recommendations of the ALJ as further modified by this order.

6. Accumulated Provision for Depreciation

In its filed case, Consumers applied the depreciation rates approved in the June 28, 2011 order in Case No. U-16054. However, the May 14, 2015 order in Case No. U-17653 altered those rates, and directed that revised rates would become effective with the issuance of the final order in the utility's next general rate case. Using the updated depreciation rates, Consumers calculated the jurisdictional projected accumulated provision for depreciation to be $4,632,583,000. Exhibit A-78. No party objected to the application of the updated depreciation figures. The ALJ recommended that the updated level of accumulated provision for depreciation be used by the Commission in its calculations, and the Commission agrees.

B. Working Capital

Consumers projected a working capital requirement of approximately $764.5 million on a total company basis for the test year. The Staff proposed a working capital amount of $607.7 million. The Staff proposed two adjustments to Consumers' calculation, which the ALJ rejected.[5]

1. Temporary Cash Investments

The Staff's first proposal is to remove temporary cash investments from working capital, on grounds that the utility would earn a double return on those funds otherwise – one from the investment itself, and one by way of a return on equity applied to the working capital balance.

The ALJ recommended rejecting this adjustment, noting that the Staff acknowledged that the utility included the projected interest earnings from its temporary cash investments as a reduction to O&M expense. *See*, 9 Tr 1954.

In exceptions, the Staff argues that Consumers is already earning a return on these investments, and that these funds exist only because the utility has excess cash and the cash is not used or useful. The Staff maintains that including the return to offset costs is avoidable, and Consumers will earn a significantly greater return if it includes this amount in working capital.

[5] A third proposed adjustment resulted in an agreement between the Staff and Consumers that, as a result of error, the utility's working capital requirement should be adjusted upward by approximately $20 million, and the corresponding revenue deficiency should also be increased by $2 million as a result. PFD, pp. 61-62.

In reply, Consumers contends that the Staff has not cited to any record evidence showing that these cash funds are not used and useful. The company maintains that it needs the added liquidity, and that its cash-on-hand is only approximately 1.6% of total electric revenues. 5 Tr 431. Consumers asserts that the Commission has approved working capital balances in electric rate cases that included temporary cash investments, citing Case Nos. U-16472 and U-16794.

The Commission is persuaded that the Staff's view is appropriate. The Commission has a long-standing practice of excluding balance sheet accounts from working capital that already earn a return. The prior cases cited by Consumers did not address temporary cash investments as a contested issue. The Commission finds that temporary cash investments should be excluded from projected working capital, since these investments already earn a return. 9 Tr 1953-1954; Exhibit S-12.2. To do otherwise would require ratepayers to fund an additional, and inappropriate, return.

2. Bonus Depreciation

The second proposed adjustment has to do with the fact that, after Consumers filed its testimony and exhibits, Congress enacted an extension of its policy awarding taxpayers bonus depreciation for new capital expenditures for the 2014 calendar year. 5 Tr 425; 26 USC 168(k). The bonus depreciation provisions had been allowed to expire at the end of 2013, and thus the effect of the extension was not reflected in Consumers' rate case filing.

The Staff argued that the bonus depreciation extension for 2014 means that Consumers could have received a refund based on an overpayment of its 2014 tax liabilities prior to the beginning of the test year. The Staff argued that the cash refund from the overpayment for 2014 should be used to immediately pay down debt and equity in equal proportion; thus, those funds would come out of working capital. The Staff contended that its proposed treatment of the bonus depreciation was based on its determination that the net additional impacts on working capital and the capital structure of deferred income taxes is zero.

Andrew J. Denato, Consumers' Director of Financial Analysis and Forecasting, testified that Consumers' working capital balance should be increased as a result of the bonus depreciation extension, because it created an intercompany tax receivable balance, which resulted in an increase to rate base of $121 million. 5 Tr 427. Consumers argued that the Staff's proposed treatment of the bonus depreciation would result in a normalization violation of the Internal Revenue Code, which requires consistent treatment between the computation of tax expense for ratemaking purposes and the calculation of depreciation for ratemaking purposes. *See*, 26 USC 168(i)(9).

The ALJ recommended rejecting this adjustment as well, finding that the Staff's position is based on conjecture. The ALJ noted that the record evidence showed that Consumers did not receive a refund of 2014 tax liabilities based on bonus depreciation prior to the beginning of the test year, and he found the Staff's position was therefore based upon an incorrect assumption.

In its exceptions, the Staff contends that its arguments have been mischaracterized in the PFD. The Staff notes that its position is based upon Exhibits S-19, S-20, S-25, S-26, S-27, and S-28. The Staff contends that these exhibits reveal that Consumers' tax sharing agreement with CMS Energy allows Consumers to receive a tax refund prior to November of the year that the consolidated tax return is filed, and that the two companies have discretion regarding the timing of the movement of cash between May 15 and November 30 of each year. In particular, the Staff argues that Exhibit S-26, a Consumers' discovery response, proves that the tax allocation agreement allows for a tentative reconciliation, made by April 30, which would have allowed the utility to receive a tax refund from the parent company by May 15 of the current year. The Staff also claims that Exhibit S-28 shows that Consumers does not intend to offset or reduce future estimated tax payments through use of the bonus depreciation refund. The Staff argues that this directly conflicts with Mr. Denato's testimony regarding the use of the refund. *See*, 5 Tr 425-427; Exhibit A-90. While acknowledging that the refund has not been received, the Staff maintains that ratepayers could have saved money if Consumers had received the refund at the earliest date allowed by the tax sharing agreement, that is, May 15, 2015. While stating that this is within the utility's prerogative, the Staff argues that it has placed a burden upon ratepayers. The Staff further argues that its position results in no normalization violation and no impact on working capital.

The Staff also argues that the ALJ erred with regard to the income tax receivable balance. The Staff notes that Mr. Denato testified that " the bonus depreciation extension also resulted in an intercompany income tax receivable balance. This income tax receivable balance will ultimately result in an increased cash balance as a result of reduced cash tax payments that the Company will have to make. Therefore, in addition to the deferred tax and other capital structure adjustments, the Company's projected working capital would **also** need to be increased." 5 Tr 427 (emphasis in original). The Staff states that it is in agreement with bonus depreciation resulting in a December 2014 income tax receivable balance of $214 million as provided by Mr. Denato's Exhibit A-93, but argues that the remainder of the exhibit and Mr. Denato's supporting testimony are purely hypothetical. The Staff contends that Mr. Denato's testimony assumes that the utility will use $100 million (increased cash balance resulting from reduced tax payments) to reduce long-term debt. 5 Tr 425-427. The Staff avers that the reduced tax payments cannot occur because Consumers will receive the entire refund. "Therefore, other than the $214 million tax receivable recorded in December 2014, all of Mr. Denato's bonus depreciation impact assumptions are hypothetical, and uncertain to occur." Staff's exceptions, p. 9.

In reply, Consumers argues that the Staff provided no record evidence in this case to support the position that it took in the initial brief on this issue. Consumers contends that there "is nothing in the record demonstrating that Staff considered the timing of the Company's tax refund or that there was any basis for its alleged determination that it would come before June 1, 2015." Consumers' replies to exceptions, p. 17. Consumers maintains that the evidence showed that tax sharing calculations are developed during the fourth quarter after completion of the federal return. Exhibit S-19. Consumers asserts that the Staff's theory about what the company would have done is unsupported in the record; and that Exhibit S-28 shows that the utility has not received the tax refund associated with bonus depreciation.

The Commission agrees with the ALJ and finds that, based on the record, the bonus depreciation amount in working capital as proposed by Consumers should be adopted.

C. Conclusion

Based on the above decisions, the Commission finds that Consumers' proposed total electric rate base should be adopted, minus the two categories of contingency costs, the temporary cash investments, and the capacity reduction proposed by the Staff, for a total jurisdictional rate base of $9,160,088,000.

IV. <u>CAPITAL STRUCTURE, COST OF CAPITAL, AND RATE OF RETURN</u>

The parties reached agreement on several components of Consumers' proposed capital structure. Remaining areas of dispute concern the common equity balance, the return on common equity, and long-term and short-term debt balances.

A. Capital Structure

1. Common Equity Balance

The ALJ reports that Consumers agreed to an adjustment proposed by the Staff, and seeks a common equity balance of $5,523,860,308. PFD, pp. 67-68. The Staff presented a further adjustment, arguing that a proposed $150 million equity infusion for the month of January 2016 should be excluded from the common equity balance. The Staff argued that this exclusion leaves the utility with a common equity ratio of 51.8%, as opposed to the 52.48% level associated with the utility's request.

The Attorney General recommended reducing the utility's proposed common equity balance by $168 million (and increasing the long term debt balance by the same amount), which, he argued, would bring the common equity ratio closer to the historical test year of level of 51.81%. The Attorney General contended that this adjustment is necessary in order to move Consumers closer to its self-proclaimed goal of maintaining a common equity ratio of 50%.

Consumers countered that both the Staff and the Attorney General seek to move closer to a 50/50 equity ratio for arbitrary reasons, and that that goal is simply a target. Consumers argued that the 52.48% common equity ratio associated with its proposed common equity balance is not a major deviation from this goal in any case, and would allow the utility to maintain a solid credit rating, ensure the smooth implementation of its ongoing capital expenditures, and allow for the pre-funding of debt maturities.

The ALJ recommended that the Commission adopt Consumers' proposed figure, finding that the utility adequately supported the request on the record. The ALJ noted Consumers' evidence indicating its reasons for needing an equity ratio slightly higher than 50%, and found that no evidence was offered in contradiction of these assertions. PFD, p. 70. The ALJ opined that the

52.48% common equity ratio constitutes only a slight increase, and noted that evidence showed that the average 2013 equity ratio for many utilities was at 52.73%. Exhibit A-91. The ALJ recommended that the Commission adopt the utility's $5,523,860,308 common equity balance proposal.

In its exceptions, the Staff maintains that it offered robust evidence for maintaining a 51.8% equity balance, and notes that Consumers may still issue 10-year debt as originally proposed.

In reply, Consumers contends that the Staff failed to support its lower equity balance, other than to simply ignore the January 2016 equity infusion.

The Commission agrees with the ALJ's thorough analysis, and finds that Consumers' proposed 52.48% common equity ratio and corresponding balance of $5,523,860,308 should be adopted. The utility provided persuasive and unrebutted evidence showing that it has sound reasons for seeking an equity ratio nominally higher than 50%, including its significant infrastructure capital investments over the next five years, its need to maintain strong credit ratings, its desire to pre-fund its debt maturities, and the fact that certain credit rating agencies include securitization debt, power purchase agreements, and benefit obligations as debt when calculating debt to equity ratios. *See,* 5 Tr 421-422. In light of these current concerns, the Commission finds that the company's proposed ratio and balance are reasonable.

2. The Effect of Bonus Depreciation on the Debt Balances

Consumers and the Staff disagreed as to whether long-term and short-term debt balances should be adjusted to reflect the effect of the bonus depreciation. Consumers' proposed figures of $4,965,225,000 for long-term debt, and $217,200,000 for short-term debt, take into account the effect of bonus depreciation. Conversely, the Staff argued that the bonus depreciation windfall should have been used to reduce debt and equity, and that it should have no effect on the capital structure or the debt balances.

The ALJ agreed with Consumers, again finding that the Staff's position is based upon the faulty assumption that Consumers received a bonus depreciation related tax refund prior to June 1, 2015, and that the utility would have immediately used that cash to pay down debt and equity in equal portions. The ALJ again found that the record did not reflect that either of these things occurred. The ALJ recommended that the Commission adopt Consumers' proposed figures for these debt balances.

In its exceptions, the Staff disagrees with the ALJ and refers to its arguments regarding bonus depreciation, laid out under the working capital section.

In reply, Consumers also refers to its arguments on bonus depreciation.

As discussed above under working capital, the Commission agrees with the ALJ and finds that it is appropriate to reflect the impact of the extension of bonus depreciation as proposed by Consumers. The Commission adopts the proposed balances of $4,965,225,000 for long-term debt, and $217,200,000 for short-term debt.

B. Return on Common Equity

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 Service 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. 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 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." *Township of Meridian v City of East Lansing*, 342 Mich 734, 749; 71 NW2d 234 (1955). With these principles in mind, the Commission turns to the factors that form the basis for determining the rate of return for Consumers.

Five parties sponsored witnesses and submitted exhibits regarding ROE. Consumers' cost of capital witness was Dhenuvakonda V. Rao, Vice-President and Treasurer, Financial Planning and Investment Relations at Consumers. Kirk D. Megginson, a Financial Specialist in the Revenue Requirements section of the Financial Analysis & Audit Division presented the Staff's case on this issue. Sebastian Coppola, an independent business consultant, testified on behalf of the Attorney General. Christopher C. Walters, a public utility consultant, testified on behalf of ABATE. Steve W. Chriss, Senior Manager, Energy Regulatory Analysis at Wal-Mart Stores, Inc., testified on behalf of Wal-Mart. The Municipal Coalition supported ABATE's proposal.

Consumers' currently applicable ROE was established in 2012 in Case No. U-16794 at 10.3%. The suggested ROEs presented by the witnesses in this case range from a low of 9.6% (ABATE) to a high of 10.7% (Consumers). The Attorney General proposes 9.75%, and the Staff supports 10.0%. The ALJ recommended an ROE of 10.0%. Accordingly, the Commission turns to the evidentiary presentations and post-hearing pleadings to assess the merits of the parties' positions and the ALJ's recommendation.

<u>Consumers</u>

Consumers' current ROE is 10.30%, which was set in both the June 7, 2012 order in Case No. U-16794 and the May 15, 2013 order in Case No. U-17087 (by settlement agreement). Mr. Rao testified in favor of an ROE of 10.7%, the midpoint in his recommended range of 10.5% to 10.9%. 5 Tr 201-296. Consumers' contended that each alternative proposal is understated, and that any ROE of 10.0% or less would "send the message to investors that Michigan is a volatile regulatory environment in which investors cannot depend upon consistent or fair regulatory treatment." Consumers' initial brief, p. 65. Consumers urged the Commission to maintain "the positive track record" that has been established with investors and rating agencies.

Consumers used a proxy approach to devising its requested ROE. For his analyses, Mr. Rao selected a proxy group of 23 publicly traded electric companies that: (1) are classified as electric utility companies by the Value Line Investment Survey (Value Line); (2) pay current common stock dividends; (3) have bonds rated at or above a minimum investment grade of Baa3 by Moody's Investor Services (Moody's) and BBB- by Standard & Poor's (S&P); (4) have 45% or more of their operating revenues from regulated electric operations; (5) have net plant greater than $5 billion; and (6) are not planning to merge with another company. 5 Tr 214-215. Consumers indicates that Mr. Rao also looked at a smaller proxy group of six companies, but concluded that it was insufficient for selecting a recommended ROE range. 5 Tr 215.

Mr. Rao testified that he: (1) studied the current outlook of the national economy and capital markets; (2) analyzed investor perceptions of the Michigan regulatory environment and risk factors associated with investment in Consumers; (3) performed standard quantitative analyses to determine the cost of equity of the proxy group and compared the risk-return profile of Consumers with other similar investments; and (4) considered current trends in the business climate for electric utilities in general and Consumers in particular. 5 Tr 214-239. As part of his assessment, Mr. Rao undertook analyses using the Capital Asset Pricing Model (CAPM) and Empirical Capital

Asset Pricing Model (ECAPM), a risk premium analysis, the Discounted Cash Flow (DCF) model, and a comparable earnings analysis.

Mr. Rao testified that, traditionally, the risk-free rate used to perform these analyses is a projection of yields on U.S. Treasury bonds, but that, as a result of unprecedented government intervention into monetary policy following the economic crisis in 2008, U.S. Treasury rates are artificially low. Therefore, Mr. Rao used a risk-free rate based on the average income return of long-term government bonds from 1926-2013 as published by Morningstar in his CAPM, ECAPM, and risk premium analyses. 5 Tr 218, 222, and 228. Mr. Rao contended that the risk-free rates employed by the Staff, ABATE, and the Attorney General are not tied to market forces, and fail to adjust for the artificially low Treasury rate.

The results of Mr. Rao's application of the models to the proxy group are presented in Exhibit A-9, Schedule D-5, p. 14. The results show a range of average ROEs of 8.94% to 10.65%, and a range of median ROEs of 9.00% to 10.69%. Mr. Rao's recommended ROE range for Consumers is 10.50% to 10.90%, with a mid-point of 10.70%. Mr. Rao described markets as volatile and the economy as fragile, and thus posits that the models understate the return that investors currently require to compensate them for risk; thus, he chose a range that differs from the ranges produced by the models. 5 Tr 214, 228. He testified that the Michigan regulatory environment is currently viewed by investors as positive and supportive, and that this perception is built into investors' expectations. 5 Tr 234-235. He further noted that over the next five years Consumers intends to invest almost $5 billion in its electric operations.

Mr. Rao responded to the arguments of other parties that, if ratemaking mechanisms such as the IRM and the RAM are approved then there should be a corresponding reduction in ROE, by stating that trackers are prevalent among utilities, and that at least one published report indicates that utilities with a decoupling mechanism do not have a lower cost of capital than utilities without one. 5 Tr 276; Exhibit A-117.

An ROE of 10.7% in combination with the capital structure and cost rates for other components as proposed by Consumers results in an overall after-tax rate of return of 6.38%. Consumers contended that if the Commission does not approve a 10.7% ROE, it should in no case set the ROE lower than the current 10.3%, as anything below this amount would be unreasonable in light of current economic conditions, the uncertainty of capital markets as a result of actions by the Federal Reserve, and the need for Consumers to raise a substantial amount of funding for planned investments.

The Staff

The Staff recommended a cost of equity range of 8.30% to 10.30%, and used 10.00% in its overall cost of capital determination. 10 Tr 2104. The Staff used a proxy group of 11 publicly traded electric utility companies to establish a reasonable cost of equity range. The Staff also applied the DCF and CAPM models, and relied on two risk premium analyses, as well as a review of other state commission ROE decisions. 10 Tr 2104-2105. The Staff's DCF analysis yielded an ROE of 8.91%. For the CAPM analysis, the Staff used an average of forecasted 2015-2016 long term U.S. Treasury bonds for the risk-free rate; this yielded an ROE of 8.60%. The Staff asserted that its risk-free rate is a more accurate reflection of the rates associated with the test year than the rate used by the utility. The Staff eschews use of the ECAPM analysis because it introduces a hypothetical alpha factor to the traditional CAPM model. 10 Tr 2119.

The risk premium analysis produced an ROE of 8.01% for the A-rated bond and 8.34% for the BBB-rated bond. The 10-year risk premium approach produced an ROE of 9.84% for the A-rated bond, and 10.46% for the BBB-rated bond. 10 Tr 2119-2121. Finally, the Staff's review of other states (2013-2014) showed an average ROE of 10.00%. Exhibit S-4, Schedule D-5, p. 13. The Staff's analysis produced a range of ROEs from 8.30% to 10.30%, and the Staff recommended that the Commission adopt an ROE 10.00% for Consumers. The Staff cited to Consumers' recently-improved credit rating from S&P, and argued that its recommendation provides the utility with over 500 basis points of spread from Consumers' highest borrowing costs. Exhibit A-9, Schedule D-2. The Staff contended that a 10.00% ROE provides Consumers with access to credit markets on favorable terms while not unduly saddling ratepayers with high rate costs. Finally, the Staff posited that if the Commission adopts either or both of the ratemaking mechanisms (the IRM or RAM), then the Commission should consider an ROE closer to the midpoint of the Staff's range (that is, 9.03%).

The Attorney General

The Attorney General recommended an ROE of 9.75%. Exhibit AG-15. Mr. Coppola also employed the DCF and CAPM methods, and a risk premium approach, as well as considering current circumstances in the capital markets and potential changes in the risk profile of CMS Energy. The Attorney General indicated that the Michigan economy has recovered and interest rates are stable, and Consumers' access to the capital markets is strong. The Attorney General objected to Consumers' risk-free rate of return as being divorced from current conditions. Mr. Coppola testified that average ROEs have declined from over 12.7% in 1990 to less than 10.0% in 2014, to 9.66% in the first quarter of 2015. Exhibits AG-16 and AG-20. Mr. Coppola stated that during the past four quarters regulatory commissions have granted an average ROE of 9.79%, and he recommended 9.75% as "a gradual transition to the true cost of equity."

ABATE

Noting that authorized ROEs in other states have been trending downward over the past two years, ABATE recommended an ROE of 9.6%. Mr. Walters testified that the national average ROE (excluding Virginia) for 2013 was 9.8%; for 2014 it was 9.76%; and for the first quarter of this year it was 9.67%. 10 Tr 2157. Mr. Walters stated that Consumers' cost of capital is lower now than it was at the time of the last rate case, and that Consumers' senior secured credit ratings from S&P and Moody's are A and A1, respectively, with a "Stable" outlook. 10 Tr 2156-2161. Mr. Walters noted that Consumers' bond ratings are both two notches higher than the average bond rating assigned to Consumers' proxy group companies, indicating a lower overall investment risk. Mr. Walters testified that Mr. Rao's CAPM results should be rejected because the historical risk-free rate ignores the current environment; and that the ECAPM analysis should be rejected because Mr. Rao used an unsupported beta. 10 Tr 2171-2174. Mr. Walters further testified that Mr. Rao used stale (September 2014) projected Treasury yields in the risk premium analysis. Mr. Walters employed an updated projection that yielded an ROE of 9.95%.

ABATE argued that the Staff's proposed ROE is also excessive. ABATE contended that the Staff failed to take into consideration the declining trend in ROEs from 2013-2015, and that Mr. Megginson's 10-year risk premium analysis covers too short a period of time to yield useful results. ABATE further contended that the Staff's risk premium analysis assumes that utility equities will outperform the broad market, when in fact utility stocks are less risky than the broad market. 10 Tr 2190.

Wal-Mart

Mr. Chriss also testified that Consumers' requested ROE contradicts the industry trend of declining ROEs, and is significantly higher than the 2014 average ROE of 9.79% approved by other state regulatory commissions. 9 Tr 1713. Mr. Chriss testified that the use of a future test year reduces regulatory lag by including all cost information for the time period when new rates will be in effect, and should result in a reduced ROE. Mr. Chriss stated that the inclusion of CWIP in rate base shifts to ratepayers risks traditionally borne by investors. Wal-Mart further argued that approval of the IRM or the RAM will reduce the risk of regulatory lag, and should result in a lower ROE. Wal-Mart pointed out that Consumers provided no evidence showing that these ratemaking mechanisms will not shorten regulatory lag, and argued that such trackers are precisely for returning capital and a return on capital between rate cases. Wal-Mart urged the Commission to reject Consumers' proposed number.

Municipal Coalition

The Municipal Coalition argued that Consumers has actually earned between 10.9% and 12.2% over the last five years – significantly higher than its authorized ROE for that time period. The Municipal Coalition supported ABATE's recommendation of 9.6%, which, the Coalition noted, is the closest recommendation to the mid-point of the Staff's range. The Municipal Coalition argued that it is simply not true that any reduction in an ROE indicates a volatile regulatory environment; and suggested that rate increases can be a marker of volatility, particularly to businesses looking to locate in Michigan. The Municipal Coalition contended that the 10.3% ROE approved in 2012 was about 30 basis points above the average at that time; and noted that, since then, costs of capital and average ROEs have declined.

The PFD

The ALJ found Consumers' requested ROE to be excessive, and agreed with the Staff's recommendation of 10.0%, giving five reasons for his decision. First, the ALJ found that the proxy group used by Mr. Rao was overly broad. The ALJ was persuaded by Mr. Coppola's reasoning for excluding certain companies and, more importantly, found that Mr. Megginson's criteria for the selection of proxy group members was superior to Mr. Rao's and produced a proxy group more closely aligned with Consumers.

Second, the ALJ found that Consumers' proposed ROE ignores the effect of the company's recently improved credit ratings. He found that these improved ratings provide the utility access to lower debt costs and an improved cash position. As such, the ALJ found, improved ratings should result in a lower ROE.

Third, the ALJ was not persuaded that Mr. Rao applied an appropriate historical risk-free rate in his CAPM analysis, which was based on the average long-term treasury bond yields from 1926 through 2013.

Fourth, the ALJ found that the information provided on the record regarding ROEs granted by other regulatory agencies throughout the country convincingly showed that Consumers' current ROE "has been, and continues to be, significantly above the national average [which, by the way, appears to have been dropping since 1990]." PFD, p. 87. The ALJ found that the record shows that authorized ROEs throughout the country have been falling for quite a while, and are most recently below 10%; and that, over the last few years, Consumers has had an authorized ROE that significantly exceeds the national average for similar operations during that period. *Id.* The ALJ stated that, based on the evidence, the utility's request to raise its ROE "has no rational justification." *Id.*

Fifth, the ALJ found that 2008 PA 286 (Act 286), since 2008, has had the effect of significantly reducing risk for Michigan utilities by providing for the use of a projected test year, the automatic implementation of rate increases, one year rate cases, and the cap on electric choice.

The ALJ noted that rate case orders issued since the act's passage have authorized Consumers to increase its electric rates by a total of $492,635,000. PFD, p. 88, note 35.

The ALJ recommended adoption of a 10% ROE, finding this falls within the range recommended by ABATE and close to the range recommended by the Attorney General. The ALJ expressed confidence in the Staff's proxy group, and in the information regarding national averages provided by Mr. Megginson, Mr. Walters, and Mr. Chriss. Noting that the Staff opined that 10% may be generous, the ALJ found it to be a reasonable reduction from Consumers' currently authorized ROE.

Exceptions and Replies

In exceptions, the Municipal Coalition objects to the ALJ's recommendation as overstated, noting that, in his analysis of average ROEs, the Staff's witness left out data from 2015 which, if included, would skew the average lower by 20-30 basis points. The Municipal Coalition argues that the average for 2013 from other state commissions was 9.80% and for 2014 was 9.76%, and for the first quarter of 2015 is 9.67%. 10 Tr 2177-2188. The Municipal Coalition urges the Commission to adopt ABATE's proposal of 9.6% because it is closer to the average.

In exceptions, ABATE argues that the ALJ ignored Mr. Walters' evidence showing that the Staff's proposed ROE is overstated. ABATE contends that the Staff used the wrong data in computing average ROEs for the 2013-2014 time period, failed to include average ROEs for 2015, and performed a flawed 10-year risk premium study. 10 Tr 2185-2187. ABATE contends that Mr. Megginson's average 2013-2014 ROE analysis included 15 ROEs that were decided in 2012, included only 65 observations when in fact there were 77 ROEs established during the 2013-2014 time period, and did not take into account the first quarter of 2015. According to ABATE, each of these changes would render an average ROE lower than 10%. 10 Tr 2187. ABATE further maintains that Mr. Megginson's 10-year risk premium analysis looks at an 11-year period that is "simply too short to measure an equity risk premium based on actual historical stock index returns," and assumes that utility stocks will outperform the broad market over time. ABATE's exceptions, p. 4; 10 Tr 2189. ABATE does not take issue with the two risk premium analyses that look at a 72-year period of time, but recommends rejecting the other two.

In exceptions, the Attorney General asserts that he provided the best record evidence on this issue and the ROE should be 9.75%. The Attorney General notes that the Staff's own witness described 10% as "generous." 10 Tr 2123. The Attorney General states that the Michigan economy has substantially recovered from the recession, that interest rates are stable, and that Consumers is in a better position with regard to sales, interest rates, access to capital markets, and uncollectibles than it was previously. The Attorney General argues that the utility's CAPM and risk premium analyses have nothing to do with current economic conditions. The Attorney General reiterates his evidence showing that, since 1990, approved ROE rates have been on a steady decline, reaching less than 10% during 2014 and 2015. Exhibits AG-20, AG-16. He contends that state regulatory commissions have been slow to embrace lower return on equity rates during a prolonged period of low interest rates, and urges the Commission to place top priority on "ending Michigan's outlier status of perpetuating unreasonably high ROEs." Attorney General's exceptions, p. 4. He posits that the current 10.3% was a product of the financial crisis and the recession years that followed, and that Michigan has now been heralded as a rebound state.

In exceptions, Consumers states that "investors are looking for confirmation that the Commission understands the investment community and the importance of authorized returns in attracting capital," and contends that the ROE should be no less than 10.3%.

Consumers points to the following quotes from the U.S. Supreme Court:

> A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding, risks and uncertainties . . . The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties.

Bluefield, 262 US at 692-93. And:

> [T]he return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital.

Federal Power Comm, 320 US at 603. Consumers argues that these seminal cases identified three criteria essential to selecting an appropriate rate of return: (1) compensation for risk which is comparable to other companies of like risk; (2) adequate return to ensure the financial soundness of the business; and (3) adequate return to maintain credit and attract capital. Consumers insists that the ALJ directed his entire analysis to the first factor – risk – and overlooked the other two.

Consumers points out that it has an ambitious capital investment program – more than $7 billion from 2015 to 2019. 5 Tr 237. The utility argues that such a large investment program implicates both the risk and the capital attraction criteria in the ROE analysis, but that the ALJ focused only on risk. Consumers contends that the ALJ also ignored the fact that interest rates will rise in the near future, and this also implicates capital attraction. Consumers avers that no party offered evidence showing that a large capital investment program and rising interest rates do not create challenges for attracting capital.

Consumers asserts that the ALJ erred in adopting the Staff's proxy group, and that he should have adopted the smaller proxy group proposed by the utility. Consumers notes that Mr. Rao testified regarding his use of two proxy groups, the smaller one (six utilities) including the additional criterion that the utilities must have less than $10 billion of net plant. 5 Tr 215. Consumers avers that the ALJ ignored this proxy group in his analysis, but that it is more closely aligned with Consumers than the Staff's group. Consumers notes that the Staff's proxy group includes utilities with up to $20 billion in net plant, and argues that all of the utilities in the smaller proxy group have credit ratings similar to Consumers. Consumers notes that its smaller proxy group analysis resulted in ROE estimates higher than the average for the larger proxy group.

Consumers maintains that the ALJ also placed undue emphasis on the risk criteria when he focused on the utility's recently improved credit ratings. Consumers emphasizes that there is an important connection between its existing level of ROE and its improved credit ratings, contending that the improved credit ratings are in part a result of its 10.3% ROE and "the signal that it sends to the financing community about the supportive regulatory environment in Michigan." Consumers' exceptions, p. 19. The utility argues that an ROE below 10.3% may result in deterioration of its credit rating.

Consumers states that the ALJ erred in his rejection of the utility's use of the historical risk-free rate for the CAPM calculation, asserting that Mr. Rao made the case that use of this rate corrects for the effect of artificially low interest rates. 5 Tr 218-219. Consumers believes that Treasury yields from September 2014 were still reasonably current in December 2014, and contends that no party contested Mr. Rao's testimony on the appropriateness of the use of an adjusted beta in the ECAPM analysis. 5 Tr 271.

Consumers further asserts that the ALJ erred in finding that the company's existing ROE is significantly above the national average. The utility again argues the ALJ placed undue emphasis on the risk criterion, and that case law holds that returns should reflect comparability in both time and location. Consumers claims that a 10% ROE lacks comparability in time because the ALJ failed to recognize that returns on equity are likely to rise during the future test period. The utility argues that it does not make sense to set the ROE based on past-approved returns, because none of them are comparable to the future test period at use here. Consumers contends that the Attorney General showed that the first quarter of 2015 reveals an increase in returns on equity, and argues that this is consistent with Mr. Rao's forecast of investor expectations. Exhibit AG-20; 5 Tr 294-295. Thus, the utility argues, even if 10.0% was a reasonable return at the present time, it should be set at a level somewhat higher in order to be comparable in the future test period.

Consumers asserts that the recommended ROE is likewise not comparable in terms of location, because the evidence presented in the case involved national data, which necessarily included utilities in states remote from Consumers' service territory. Consumers states that it used data from the Staff's Exhibit S-4 to compute the average ROE resulting from recently decided cases in Indiana, Michigan, Ohio, Pennsylvania, and Wisconsin, and the result was 10.26%.[6] Consumers asserts that this is a more accurate average ROE for comparison purposes because it involves "the same general part of the country" as is required under *Bluefield*. Factoring in an adjustment for comparability in time, Consumers argues that its ROE should be well above 10.3%.

Finally, Consumers maintains that the ALJ erred in concluding that Act 286 reduced business risk for utilities. Rather, Consumers asserts that the improvement in the state's regulatory environment "suggests a previously deficient regulatory paradigm." Consumers' exceptions, p. 33. The utility contends that financial analysts view Michigan as more risky than other states, and that investors are looking for a long and consistent track record from the regulatory environment.

[6] Consumers excluded Illinois because that state uses a formula ratemaking paradigm. Consumers' exceptions, p. 29, note 4.

Consumers asserts that if the Commission can place comparable emphasis on all three legally required considerations, it will approve an ROE of no less than 10.3%.[7]

Several parties filed replies on this issue. The Municipal Coalition argues that the Staff's analysis is outdated and overstated, and that Consumers' request for 10.7% was a cynical move intended to persuade the Commission to retain 10.3% for the utility in the face of clearly declining ROEs nationwide. The Municipal Coalition states that the evidence shows that Consumers has actually earned between 10.9% and 12.2% over the last five years. *See*, 10 Tr 2268.

The Municipal Coalition supports ABATE's position, noting that market costs of capital are less today than when the 10.3% ROE was set. The Municipal Coalition posits that Consumers forgets that this Commission must consider more than Consumers' needs, including the health of the economy, the impact on ratepayers, the impact on local governments and taxpayers, and the effect on businesses considering locating in Michigan. The Municipal Coalition asserts that an ROE that is in line with the national average would signal a less volatile environment for new business investment.

ABATE also refers to Mr. Walters' testimony regarding the decline in the average ROE nationally over the last several years, and argues that the ALJ appropriately considered Consumers' improved credit rating and bond ratings that exceed the proxy group's, in his analysis. ABATE asserts that an improved credit rating leads to a lower cost of capital. ABATE also supports the use of current forecasted interest rates in the assumption because those are the rates that are related to investment expectations.

The Attorney General argues that Consumers cherry-picked favorable ROEs to support the notion that its ROE should not be lowered.

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[7] Consumers does not address its request for a 10.7% ROE in its exceptions.

The Staff argues that the ALJ appropriately examined the role of the credit rating in his ROE analysis, as well as the data on other recently-approved ROEs. The Staff also characterizes Consumers' data as cherry-picked, noting that if Minnesota, Illinois, and Iowa are added into the mix of states "in the same general part of the country" then the average ROE is 10.0%.

Consumers filed replies, repeating its arguments in support of a 10.3% ROE.

The Commission agrees with the utility and finds that the current 10.3% ROE should be continued. While the ALJ provided an excellent analysis of this issue, the Commission finds that the current ROE will best achieve the goals of providing appropriate compensation for risk, ensuring the financial soundness of the business, and maintaining a strong ability to attract capital.

Consumers has planned an ambitious capital investment program, much of which is related to environmental and generation expenditures that are unavoidable and are saddled with time requirements. The Commission observes that 10.3% is at the upper point of the Staff's recommended ROE range, and Consumers showed, using the Staff's exhibit, that the average ROE resulting from recently decided cases in Michigan, Indiana, Ohio, Pennsylvania, and Wisconsin was 10.26%. The Commission acknowledges that ROEs, nationally, have shown a steady decline (as they have in Michigan), and agrees with the Attorney General that Michigan's economy has stabilized; but finds that, under present circumstances, it is reasonable to assume that investor expectations may be rising. Consumers' recently-improved credit ratings will help the utility secure the financing required to carry out its goals. Thus, the Commission favors adopting an ROE of 10.30%.

C. Cost of Long-Term Debt

Consumers requested an embedded long-term debt cost rate of 5.02%, in part based on applying a 5% interest rate to a proposed July 2015 debt issuance. The Staff argued in favor of an embedded 4.94% long-term debt cost rate. The Attorney General supported 4.95%.

The ALJ recommended adoption of Consumers' proposed rate, finding it to be better supported on the record than the other proposals. The ALJ noted that U.S. Treasury rates have been trending upward, and cited his prior findings with regard to the effect of the bonus depreciation.

The Commission finds that the Staff's updated long-term debt cost rate of 4.94% should be adopted. The Staff relied on a new 10-year debt issuance, which is reflected in the Staff's embedded long-term debt cost of 4.94%. The Commission finds that this is more reliable than the 30-year issuance rate proposed by Consumers late in the case.

D. Cost of Short-Term Debt

Consumers eventually agreed with the Staff's proposed short-term debt cost rate of 1.83% as a starting point, but argued that this rate needed to be revised to reflect the effect of the bonus depreciation. Consumers contended that this figure should be adjusted downward to 1.73%. The ALJ agreed, and recommended that the Commission adopt a short-term debt cost rate of 1.73%.

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

E. Conclusion

Based upon the above decisions, the Commission adopts an ROE of 10.3%, a pre-tax weighted cost of 8.9205%, and an overall rate of return for the test year of 6.18%, as reflected below:

Description	Amount (000)	Ratio	Cost Rate	Weighted Cost
Long-Term Debt	$ 4,965,255	37.30%	4.94%	1.84%
Preferred Stock	37,315	0.28%	4.50%	0.01%
Common Equity	5,523,860	41.50%	10.30%	4.27%
Short Term Debt	217,200	1.63%	1.73%	0.03%
Deferred FIT	2,528,157	18.99%	0.00%	0.00%
JDITC				
Long-term Debt	18,715	0.14%	4.94%	0.01%
Preferred	141	0.00%	4.50%	0.00%
Common Equity	20,821	0.16%	10.30%	0.02%
Total	$ 13,311,464	100.00%		6.18%

V. ADJUSTED NET OPERATING INCOME

A. Sales and Revenue Forecast

For the test year, Consumers projected its jurisdictional electric sales to be 37,726 gigawatt-hours (GWh). The Staff determined that Consumers' revenues should be $4,229,447,000, which is $1,261,000 more than proposed by the company. Subsequently, Consumers provided additional sales revenue information and the Staff is now in agreement with the company's proposed sales revenue of $4,228,186,000.

The Attorney General objected, stating that although the company completed its sales forecast projection in October 2014, it only included sales data through 2013. The Attorney General argued that the company should be required to provide a more current forecast and he requested that the Commission accept the sales forecast set forth in Exhibit AG-1, which shows electricity sales for the future test year to be 38,095 GWh.

In response to the Attorney General's request, Consumers stated that it has since completed a sales forecast in April 2015, and it projects 37,813 GWh of electric sales for 2015-2016. Therefore, if the Commission adopts the Attorney General's suggestion of using the most recent sales forecast information, Consumers requested that the April 2015 sales forecast information be accepted, which would result in an estimated increase of operating revenues of $348,000.

The ALJ found that the company's most recent sales forecast should be adopted, and as a result, accepted Consumers' April 2015 forecast.

No party filed exceptions on this issue; however, the Commission declines to adopt the ALJ's recommendation. Although Consumers' witness, Hubert W. Miller, III, briefly discussed the April 2015 sales forecast in his testimony, it was not admitted as evidence on the record. Consequently, the Commission cannot perform a detailed revenue analysis for rate design and cost-of-service purposes. In any event, the Commission notes, the operating revenue increase of approximately $348,000 resulting from the use of the April 2015 sales forecast is negligible. Therefore, the Commission finds that Consumers' proposed revenue forecast, as updated by the Staff, of $4,228,186,000 is supported by the record, and is therefore accepted. On a jurisdictional basis, the revenue forecast is $4,203,587,000.

B. Operating Expenses

1. Staff's Proposed Budget-based Adjustment

According to the Staff, Consumers presented a budgeted O&M amount of $588,163,000 to its Board of Directors in January 2015, which is $58.7 million less than the company requested in its rate case filing. The Staff requested that the Commission adopt Consumers' budgeted amount of $588,163,000 for the following three reasons: (1) the company failed to demonstrate that it cannot provide safe and reliable service for the January 2015 budgeted amount; (2) Consumers did not provide the payroll included in the projected test year; and (3) the company did not breakdown historic reinvestment of incremental earnings, which makes comparison of budget O&M to actual O&M less useful when determining the actual incremental benefits of reinvestment. The Staff asserted that it conducted a comprehensive review and analysis of Consumers' rate case filing, investor presentations, the January 2015 budget presented to the Board of Directors, and historical actuals, and found that Consumers could provide safe and reliable service for the January 2015 budgeted amount.

In response to the Staff's recommendation, Consumers alleged that the Staff "offer[ed] no analysis or explanation to support its claim that using budget amounts is more reasonable." *Id.*, p. 75. Consumers also claimed that the Staff's audit request did not ask for payroll information or a breakdown of historic reinvestment amounts. In any event, Consumers argued that it provided detailed evidence and supporting explanations for its O&M projections for the test period. *Id.*, p. 76. The company explained that "budget amounts are developed for very different purposes than rate case projections and are not a suitable indicator of future O&M expense needs." *Id.*, p. 79.

ABATE indicated that it supported the Staff's position on this issue.

Although the ALJ recognized the inherent logic of the Staff's position and stated that his decision was a "close call," the ALJ declined to adopt the Staff's recommendation for three reasons: (1) the Staff failed to provide any real analysis for the specific area-by-area revisions to O&M spending in Exhibit S-3, Schedule C5, lines 1-14, column e; (2) Consumers is correct that a utility's annual budget and a rate case filing serve different purposes; and (3) the company's annual budget needs "to be at least somewhat conservative with regard to estimating what future revenues will be, [and] it seems reasonable for Consumers' management to refrain from blindly assuming that every dollar of rate relief requested in a rate case" will be granted. PFD, p. 103. The ALJ found Consumers' presentation "adequate--particularly in light of recent Commission decisions in gas and electric rate cases alike--to allow for at least the potential adoption of its projected O&M figures instead of those included in its January 2015 Budget." *Id.*, p. 102 (footnote omitted). However, the ALJ noted that his recommendation does not affect requests to revise specific areas of the company's O&M expenses for other reasons set forth by the Staff.

Although the Staff agrees with Consumers and the ALJ that the company creates its budget and its rate case filings for different purposes, the Staff asserts in its exceptions that this does not prohibit the Commission from making the proposed budget adjustment. In the Staff's opinion, "The fact that the Company created them for different purposes only strengthens Staff's argument that the board-reviewed budget is a more accurate estimate of the Company's needs than projections developed for a rate case." Staff's exceptions, p. 3. In addition, while agreeing with the ALJ that the company must be conservative in estimating its budget, the Staff observes that Consumers spent (on average) $29 million more than budgeted, and its revenues were $70.5 million more than budgeted. Therefore, the Staff argues, "This demonstrates that the Company's budgeting methods, on average, result in a net positive to the Company of $41.5 million per year through its necessarily conservative budget process." *Id.*, p. 4.

On page 34 of its replies to exceptions, Consumers asserts that the ALJ is correct that the "Staff's proposed budget-based disallowances are inappropriate and would result in insufficient revenue to cover the company's O&M needs to provide safe and reliable electric service to its customers." Consumers reiterates the arguments set forth in its brief and reply brief, contending that it provided detailed evidence and supporting testimony for its proposed O&M expenses.

Although the Staff presents a compelling argument, the Commission agrees with the ALJ that a utility's annual budget and a rate case filing serve different purposes. Consumers aptly stated, "a rate case filing is designed to explain and support the full scope of the Company's expected expense and revenue needs in a future period of time in order to seek funds to meet all of its needs, [whereas] the Company's annual budget must limit planning to address needed expenses in such a way that the Company can operate within the constraints of the resources it already has or reasonably can expect." Consumers' initial brief, p. 92. In addition, the Commission recognizes that Consumers must be conservative in estimating its future revenues for its annual budget, knowing that the Commission is not likely to grant every dollar of rate relief requested. As a result, although the Commission continues to find budget information relevant to the rate case process**,** the Commission declines to adopt the Staff's proposed budget adjustment.

2. Distribution and Energy Supply Operations and Maintenance Expenses (Excluding Advanced Metering Infrastructure)

Consumers stated that its O&M expense projections for electric distribution and energy supply are $239,439,000 on a total company basis for the test year. According to the company, the majority of the O&M expenses for this area involve energy operations, energy delivery, and customer operations (excluding uncollectible expenses). Consumers' initial brief, p. 97. The following four O&M expense projections are in dispute.

a. Vegetation Management/Line Clearing

Consumers projected $57,700,000 for vegetation management, which includes line clearing within the company's rights-of-way (ROW) and removing hazardous trees outside of the company's ROW. In Consumers' opinion, this amount will allow the company to clear approximately 25%, or 1,170 miles, of its HVD system, and approximately 14%, or 8,000 miles, of its primary LVD system annually. Consumers' initial brief, p. 97. The company stated that "[b]ased on the recommendations of an outside consultant, Environmental Consultants Inc. [ECI], the Company's projected expense level supports the utilization of a seven-year average cycle for its LVD line-clearing program, and will allow the Company to address dead or dying hazard trees that are up to 20 feet outside of the right-of-way." *Id.*, pp. 97-98.

The Staff recommended reducing Consumers' requested vegetation management amount to $44,550,000, which is the last Commission-approved amount for vegetation management, but agreed to an additional $3,950,000 for hazardous tree removal outside of the ROW. According to the Staff, the reduction is appropriate because:

1. After two years of the current funding level of the program, the Company has recorded the lowest SAIFI [System Average Interruption Frequency Index] numbers in 10 years. [8 Tr 1305.]
2. The Company has not spent over $45,200,000 on the line clearing program historically (Exhibit S-8.2 (RSL-2)), although it has overspent its budget overall in distribution operations and maintenance (O&M) in each of the last 4 years. [8 Tr 1353.] Staff's investigation into the December 2013 Ice Storm concluded that significant reliability improvements could be derived from an outside the ROW program. [9 Tr 1906.]

Staff's initial brief, p. 78.

The Staff requested that the Commission reject Consumers' projected vegetation management expense because the company failed to provide evidence that the increased budget level will have corresponding benefits for ratepayers. In the Staff's opinion, Consumers has overspent for electric distribution for the last four years and reinvested in O&M programs late in the year so as to balance earnings and continue to earn its authorized ROE. Consequently, the Staff contended, there is no assurance that Consumers will actually spend the increased budget on vegetation management. The Staff asserted that vegetation management is the best strategy for preventing customer outages, and thus "the program [should] be the first to see reinvestment over the approved budget, if the reinvestment was [in fact] customer benefit focused." Staff's initial brief, p. 79. Therefore, the Staff stated, maintaining Consumers' current Commission-approved level of funding will permit the company to continue to improve customer reliability, continue its current tree-trimming schedule, and achieve the full benefits of their current cycle length. *Id.*, p. 80.

Additionally, the Staff requested that the Commission only approve its proposed hazardous tree trimming allowance in the event the Commission also approves the Staff's metrics to closely monitor spending on this program. The Staff's metrics are as follows:

1. Number of outages caused by trees outside the ROW;
2. Number of trees marked for removal;
3. Definition of what renders a tree hazardous;
4. Customer acceptance of the program (accept vs. decline);
5. All complaints regarding the outside the ROW program. [9 Tr 1907.]

Staff's initial brief, p. 81. According to the Staff, Consumers does not keep data on trees outside of the ROW, and the extent of the problem and benefits of such a program are unknown to the company and the Staff. Contrary to the company's assertion that the metrics would be burdensome, the Staff argued that they are "necessary to ensure that ratepayers are only paying for reasonable and prudent costs." *Id.*

Consumers responded that there is no evidence supporting the Staff's argument that the company overspent its O&M budget because it exceeded its authorized rate of return. Consumers asserted that the Staff's argument failed to "address reasonableness of the Company's Line-Clearing expenses, and ignores the record evidence in support of the expense amount calculated by the Company." Consumers' reply brief, p. 84. In addition, Consumers stated that it does not have the data to meet the specifics of the Staff's proposed metrics to monitor hazardous tree removal from outside the ROW. However, the company was "willing to meet with the Staff and other interested parties as a part of a collaborative effort to determine what data would be available and useful for an analysis of the ROW Program." Consumers' reply brief, p. 86.

The Attorney General proposed reducing Consumers' projected vegetation management expense to $40,000,000. The Attorney General noted that the company's request is 43% more than the amount spent on tree-trimming in 2014, and more than double the amount spent in 2013. In addition, the Attorney General stated that Consumers requested $53 million for tree-trimming in Case Nos. U-16794 and U-17087, but has yet to spend anywhere close to that amount in any year in the last decade. The Attorney General pointed out that the Commission approved $44.6 million for tree-trimming in those two aforementioned cases.

According to the Attorney General, a review of the study conducted by Consumers' consultant, ECI, shows that the cost of the first cycle of tree-trimming would be between $43 and $55 million, depending on whether it was done every 7 or 8 years, and the second cycle would cost between $34.4 and $38.5 million, again depending on whether it was done every 7 or 8 years. Attorney General's initial brief, p. 12. The Attorney General stated that the average of the two cycles is $38.7 million, and if the Commission were to round up to $40 million, that would be sufficient funding to provide effective vegetation management.

In response, Consumers asserted that the Attorney General's "method of determining an appropriate expense does not focus on what is needed for the Company to continue making improvements in reliability and reducing outages," and requested that the Commission reject the proposal. Consumers' reply brief, p. 100.

The ALJ agreed, in part, with the Staff and the Attorney General, stating that the "record clearly reflects a lack of commitment to tree trimming on Consumers' part, which is apparent in both the annual levels of its actual spending on this area, and the unevenness of that spending on a year-to-year basis." PFD, p. 106. Thus, the ALJ recommended that the Commission reject Consumers' projected $57.7 million vegetation management expense, and instead recommended adopting the Attorney General's proposed "two-year average of projected spending derived from ECI's analysis for an 8-year tree trimming cycle, while also adding the Staff's suggested $3,950,000 allowance to address trees outside of the ROW." *Id.*, pp. 107-108. Regarding the Staff's proposed metrics to monitor hazardous tree removal from outside the ROW and Consumers' response that it would be willing to meet in a collaborative effort, the ALJ found that the company's proposal was a "reasonable compromise, at least on a temporary basis, and therefore recommends that the Commission order Consumers to participate in the proposed collaborative." *Id.*, p. 108.

Consumers excepts, asserting that the ALJ's recommendation does not provide the company with a reasonable amount for line-clearing and fails to consider that the company's projected expense is designed to increase customer satisfaction and reliability. Responding to the ALJ's determination that the company consistently spends less on vegetation management than authorized by the Commission, Consumers disagrees and states that it is attempting to "manage its spending across the utility portfolio, and funding for line clearing, service restoration, and other

Electric Distribution O&M expenses must be balanced." Consumers' exceptions, pp. 38-39. Consumers asserts that it provided evidence that clearly shows the basis for and the benefit of the projected vegetation management expense, and that the expense amount is consistent with the Commission's order addressing the 2013 ice storm report.

Consumers also objects to the ALJ's adoption of the Attorney General's proposal to use a two-year average of projected spending based on ECI's analysis for an eight-year tree-trimming cycle. Consumers argues that the ALJ's finding misrepresents ECI's report and his conclusion is unsupported by the record.

The Commission finds the Staff's proposed vegetation management amount of $44,550,000 to be the most persuasive. The Commission observes that the company has never spent more than $45 million annually on the line clearing program, and accordingly, is unlikely to spend the requested $57.7 million. The Commission agrees with the Staff that vegetation management is the best strategy for preventing customer outages, and until Consumers shows that it shall consistently spend the Commission-approved amounts for line clearing, the Commission finds that the currently-approved vegetation management amount of $44,550,000 is appropriate to allow the company to continue its current trim cycle and to improve customer reliability.

Consistent with the PFD, the Commission also approves the Staff's proposed $3,950,000 for hazardous tree removal outside of the ROW. Both the Staff and Consumers agree that there are benefits to removing hazardous trees outside the ROW, such as improving a level of customer reliability that is not available under current practices. The Staff requested that the Commission approve five metrics for monitoring the hazardous tree removal program, however, Consumers argued that as of now, it does not have the data to meet the Staff's criteria. The ALJ noted that the company was willing to meet in collaboration with the Staff to determine "what data would be available and useful for an analysis of the ROW Program," and found that Consumers' suggestion was an acceptable compromise. Consumers' reply brief, p. 86. The Commission agrees, and directs the company and the Staff to meet within 90 days of the date of this order to discuss future analysis of the ROW program.

b. Smart Energy Customer Program Operations and Maintenance Expense

Ms. Palkovich testified that the company is requesting $3,700,000 for the marketing of and enrolling customers in demand response programs (which partially involve the use of DLA switches), such as dynamic pricing and DLA. In the rate base section of its brief, the Staff recommended disallowing all costs associated with DLA switches, and accordingly, requested that the Commission reject Consumers' projected O&M expenses for DLA switches. The Attorney General also opposed Consumers' projected expenses for the DLA switches, stating that the company's plan lacks details showing how and when the money will be spent. He recommended that at least half of the expenses, or $1.8 million, should be removed from Consumers' projected O&M expenses.

Consumers responded that although the Staff prefers a smart thermostat program, the Staff's program is premature and undefined, and does not affect the reasonableness of Consumers' proposed program. And, in response to the Attorney General, Consumers argued that the "expense level for the Smart Energy DLA Program is necessary to achieve customer enrollment targets and to support peak demand reductions in the test year." Consumers' reply brief, p. 102.

Contrary to the Staff's and the Attorney General's concerns, the ALJ found the company's projected expenses to be reasonable and prudent. The ALJ stated that "the Staff's concern regarding the selection of a particular DLA switch…was considered and rejected earlier in the PFD." PFD, p. 109. Regarding the Attorney General's proposed reduction to O&M, the ALJ asserted that Consumers did, in fact, present testimony and an exhibit with specific plans for the program. Therefore, the ALJ recommended that the Commission approve the entire $3.7 million expense for Consumers' Smart Energy Customer Program.

No party filed exceptions on this issue, and the Commission adopts the findings and recommendations of the ALJ.

c. Distribution Technology Programs' Operations and Maintenance Expense

Consumers requested an increase in O&M expenses of $3,900,000 for distribution technology programs. The Attorney General opposed $2 million of Consumers' proposed costs because, in his opinion, the costs appear premature and excessive.

The ALJ recommended that the Commission reject the Attorney General's expense reduction because he provided no evidence to support his request and Exhibit AG-6 shows that the Attorney General's witness was notified by the company of "the necessity of incurring those expenses and the details surrounding that projected incurrence." PFD, p. 111.

No party filed exceptions on this issue, and the Commission adopts the findings and recommendations of the ALJ.

d. North American Electric Reliability Corporation Standards Compliance Costs

Consumers projected an increase in O&M expenses of $3,200,000 for distribution and transmission North American Electric Reliability Corporation compliance costs. According to Ms. Palkovich, a portion of the increased costs is related to Consumers registering as a transmission owner/transmission planner/transmission operator (TO/TP/TOP).

The Attorney General objected to $2 million of Consumers' projected costs for registering as a TO/TP/TOP because it was unclear in the company's filing what additional compliance work was necessary for registration and whether the $2 million will actually be spent during the forecasted test year.

The ALJ found that Consumers has a good understanding of the registration process to become a TO/TP/TOP and the necessary compliance work. Therefore, the ALJ recommended that the Commission reject the Attorney General's requested reduction.

No party filed exceptions on this issue, and the Commission adopts the findings and recommendations of the ALJ.

3. Fossil- and Hydro-based Generation Operations and Maintenance Expense

Consumers stated that its projected fossil- and hydro-based generation O&M expense for the test year is $176,827,000. According to Mr. Kehoe the "Test Year Base O&M was calculated using a linear regression which results in annual decreases of 9.1%." Consumers' initial brief, p. 107. Mr. Kehoe noted that the decrease was the result of reduced operations at some of the company's coal-fired units. The decrease, however, was adjusted upward to reflect added expense related to federal and state environmental compliance costs for the installation, maintenance, and operation of AQCS, the purchase and operation of the Jackson Plant, and a few major maintenance projects.

The Staff recommended a $15,741,000 reduction, stating that its adjustment is "a result of aligning the Staff rate case projection to the Company budget as presented to the Board of Directors." Staff's initial brief, p. 71. The Staff explained that it is unreasonable for the Commission to approve $176,827,000 for the projected test year "when the two year projected average for 2015 and 2016 that the Company is presenting in this rate case is $159,829,000." *Id.*, p. 72.

The Attorney General disputed two portions of Consumers' requested fossil- and hydro-based generation O&M expense, and requested a total disallowance of $12.9 million. In his first objection, the Attorney General argued that Consumers "used the expense projection for the full year of 2016 instead of pro-rating a portion of 2015 and 2016 expenses to calculate the applicable amount for the June 2015 to May 2016 test year." Attorney General's initial brief, p. 16. In addition, he contended that the new AQCS projects that are under construction at two coal-fired units will not be in service until April 1, 2016, and June 1, 2016, which is near the end, or after the conclusion of, the test year. Accordingly, the Attorney General recommended removing $7.9 million from the company's O&M expenses.

In the Attorney General's second objection, he noted that Consumers requested 12 months of O&M expense for the Jackson Plant. However, he stated that the company expects to purchase and take possession of the plant in January 2016, which results in only five months of O&M expenses for the test year. As a result, the Attorney General requested that the Commission disallow $5 million of Consumers' O&M expense for the Jackson Plant.

MEC/NRDC agreed with the Attorney General that $5 million should be removed from Consumers' O&M expenses for the Jackson Plant. MEC/NRDC stated that pursuant to Act 286, Consumers is permitted to request rate recovery for expenses that will occur in a future 12-month period, however, "[t]he statute does not authorize the utility to use a future consecutive 19-month period for expenses associated with an asset if it will be acquired part-way through the test year." MEC/NRDC initial brief, p. 48.

The ALJ disagreed with the Attorney General and MEC/NRDC. In response to the Attorney General's objection to the AQCS expenses, the ALJ stated that his argument is not supported by the record. The ALJ noted that Mr. Kehoe testified that Consumers began operating its emissions controls at the Karn plant in June 2014 in order to comply with the MATS, "which required a reduction in mercury air toxins on or before April 2015." *Id.*, citing 6 Tr 726. Then, according to the ALJ, Mr. Kehoe stated that Consumers will begin operating its emissions controls at Campbell in February 2016, which falls within the future test year. Additionally, the ALJ asserted that the Attorney General and MEC/NRDC provided a much too strict interpretation of the provisions of MCL 460.6a(1), which would "inappropriately limit the utility's recovery to only a portion of the annual O&M costs for facilities that will be operating well beyond the 2015-2016 test year." *Id*. In the ALJ's opinion, such an interpretation could force Consumers to immediately file another rate case in order to recover reasonable and prudent O&M expenses.

On page 61 of its exceptions, Consumers concedes that it "does not currently expect to own the Jackson Gas Plant at the time rates go into effect;" nevertheless, the Commission should approve rates that include the costs of the Jackson Plant. Consumers explains that, "the first phase would simultaneously include a conditional offsetting credit that would be equal to the costs associated with the Jackson Gas Plant and remain in effect until the Company closes on the plant." *Id.* Then, after Consumers closes on the Jackson Plant, the credit would automatically cease, "and the rate increase described in the first stage would continue until the retirement of the Company's seven small 'Classic 7' coal plants expected in April 2016." *Id.* Upon the retirement of the Classic 7, Consumers proposes to reduce its rates to reflect the removal of approximately $38 million of O&M costs associated with those plants. *Id.* Consumers states that, because no party contested its proposal, there was no record evidence opposing it, and the ALJ did not explicitly address the proposal, the Commission should approve the company's recommended rate relief.

The Staff notes in its exceptions that the ALJ did not address its arguments regarding the fossil- and hydro-based generation O&M expense. For clarification, the Staff states that its recommended reduction does not relate to its requested budget adjustment. Rather, the Staff argues, "The Company's own projections for 2015 and 2016 simply do not support granting an extra $17 million in rate relief above the Company's own projection." Staff's exceptions, p. 5. Therefore, the Staff requests that the Commission approve its recommended $15,741,000 disallowance.

The Attorney General also excepts, reiterating that the Commission should approve his proposed $12.9 million reduction. He argues that pursuant to MCL 460.6a(1), his proposed reduction is proper and not overly restrictive.

In its replies to exceptions, Consumers disputes the Staff's claim that its proposed reduction to fossil- and hydro-based generation O&M expenses is not based on the Staff's proposed budget adjustment argument. Consumers contends that Mr. Nichols' argument cites only to the budget book presented to the company's Board of Directors, that Mr. Nichols performed no analysis regarding the projected fossil- and hydro-based O&M expenses, and that, based on Mr. Nichols' lack of analysis, he had "no way of knowing" if the company's projected base O&M for the test year was correct. Consumers' replies to exceptions, p. 43. By comparison, Consumers argues:

> The Company's evidence in support of its projected Fossil and Hydro Generation O&M comprehensively considers a multitude of factors which includes past O&M spending and individual drivers of O&M expenses. The Company's Fossil and Hydro Generation O&M projections in this case are the costs required for the Company to continue to be able to provide safe, reliable, and efficient electric generation. 6 Tr 723. The cost projections are the result of a comprehensive process that utilizes historical analysis, Internal Rate of Return ("IRR") and Present Value Ratio ("PVR") analyses, and senior management approval. 6 Tr 724. Moreover, the Company has consistently spent the amounts that it has requested for Fossil and Hydro Generation.

Id., pp. 44-45. As a result, Consumers requests that the Commission reject the Staff's proposed adjustment.

Consumers replies to the Attorney General that Karn began operating air quality emission controls in June 2014 so that it could comply with the MATS, and Campbell units 1, 2, and 3 will begin operating air quality emission controls in February 2016. Consumers explains that it "projected a full year of expense at these units to allow full recovery of the Environmental Operations revenue requirement. 6 Tr 727. All emissions equipment in question will become operational during the test year and customers will receive the full benefit of this equipment when it becomes operational." Consumers' replies to exceptions, p. 56.

Consumers states that the Attorney General's proposed reduction to O&M expenses for the Jackson Plant does not account for the company's operating costs. To recover the Jackson Plant's revenue requirement, Consumers included a full year of 2016 operating expenses. Consumers argues that, "If the Company were forced to use a revenue requirement based on the purchase date of the plant, as suggested by Mr. Coppola, the Company would collect only five months of the full revenue for a plant that will be operating well beyond the test year in this case." Consumers' replies to exceptions, p. 56. According to the company, the Jackson Plant will be purchased in January 2016, will become operational during the test year, and customers will receive the full benefit of the Jackson Plant.

In response to the Attorney General's argument regarding test period cost recovery, Consumers asserts that it is "an overly restrictive and incorrect interpretation of MCL 460.6a(1) that is inconsistent with the intent of test periods." Consumers' replies to exceptions, p. 57. Consumers argues that the language of MCL 460.6a(1) does not require that the Commission use a specific methodology in setting rates, so long as the results are just and reasonable. In addition, Consumers avers that a test period should not be unreasonably restricted to cost recovery for a defined period of time without proper consideration of the company's actual costs of service;

"Rather, the point of a test period is to set rates which reasonably reflect the Company's actual costs of providing service during the time in which future rates will be in effect." *Id.*

The Commission agrees with the ALJ. The Commission finds that in order to comply with the MATS, Consumers began operating its emissions controls at the Karn plant in June 2014. In addition, Consumers provided testimony that it will begin operating its emissions controls at Campbell in February 2016, which falls within the future test year. The Attorney General's and MEC/NRDC's interpretation of the provisions of MCL 460.6a(1) is much too stringent, and will force the utility to recover only a portion of the annual O&M costs for facilities that will be operating during the test year and beyond. Therefore, the Commission rejects the Attorney General's and MEC/NRDC's proposed reductions.

It appears that the ALJ implicitly denied the Staff's proposed adjustment because it was perceived to be connected to the Staff's proposed budget adjustment, which was previously rejected by the ALJ. The Commission shares the ALJ's opinion, noting that the Staff stated that its adjustment "was a result of aligning the Staff rate case projection to the Company budget as presented to the Board of Directors." Staff's initial brief, p. 71. As discussed above, the Commission declined to adopt the Staff's proposed budget adjustment, and for the same reasons, declines to adopt the Staff's proposed fossil- and hydro-based O&M expense adjustment.

Regarding the expenses for the Jackson Plant, the Commission finds Consumers' proposal set forth in its exceptions persuasive. Therefore, the Commission approves the company's proposed conditional offsetting credit that would remain in effect until Consumers closes on the plant, at which time the credit would cease, and the rate increase described above will continue until the retirement of the Classic 7. Following the retirement of the Classic 7, Consumers shall reduce its rates by approximately $38 million for O&M costs associated with those plants.

4. Corporate Services Operations and Maintenance expense

For its corporate services O&M, Consumers projected that its test year expense is $54,285,000. The Staff recommended three adjustments to Consumers' projected expense: (1) removal of interest income of $105,000; (2) an insurance adjustment decrease of $2,504,000; and (3) a budget adjustment increase of $4,542,000.[8] Regarding the insurance expense adjustment, the Staff used 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. Staff's initial brief, pp. 86-87.

Consumers responded that, "Due to the sporadic nature of these refunds and/or credits, the timing and amount of future refunds and credits cannot be relied on to occur with any certainty." Consumers' reply brief, pp. 89-90. As a result, the company asserted that these insurance refunds and/or credits should be considered "non-recurring items and normalized out of ongoing expenses." *Id.*, p. 90. In addition, Consumers argued that the Staff's recommended disallowance conflicts with the Staff's other O&M adjustments and, therefore, should be rejected.

The ALJ found Consumers' argument unpersuasive, and adopted the Staff's suggested "five-year average to estimate the test year level of net insurance-related expenses." PFD, p. 116. The ALJ noted that both Consumers and the Staff agree that the timing of insurance refunds and/or credits fluctuates, but the ALJ agreed with Mr. Nichols' testimony that although "refunds, credits, and distributions fluctuate, they are expected to occur in the future and the Company should continue to receive similar amounts." *Id.*, citing 9 Tr 1991-1992. In addition, the ALJ stated that

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[8] In accordance with its decision regarding temporary cash investments, the Commission accepts the removal of the interest income of $105,000; and in accordance with its decision regarding the Staff's proposed budget adjustment, the Commission rejects the proposed budget adjustment increase.

using a five-year average for insurance related O&M expenses "coincides with the utility's own proposed treatment of its injuries and damages expense." *Id.*, p. 117.

In its exceptions, Consumers argues that the Staff misunderstands the company's insurance expense, stating "The receipt of insurance funds and/or credits is not a 'regular occurrence,'" and instead is "very sporadic due to the volatility of investment markets and future claims experience." Consumers' exceptions, p. 44, citing Staff's initial brief, p. 90. Consumers also claims that the Staff's recommendation conflicts with the Staff's other O&M expense adjustments, and it seems that "Staff appears to have selectively cherry-picked certain budget data which supports its desired result and rejected other budget data that is in conflict with Staff's desired result." *Id.*

The Staff replies that the ALJ correctly determined that the Staff's five-year average provides the best estimate of the company's insurance expenses because it demonstrates that there were no extraordinary events regarding Consumers' premiums, and that insurance premiums "are not trending noticeably upwards." PFD, p. 117, citing 9 Tr 1992.

The Commission adopts the recommendation of the ALJ, agreeing that the Staff's proposed five-year average for net insurance-related expenses is appropriate. Although insurance refunds, credits, and distributions may fluctuate, the Commission finds, based on the record, that they are likely to occur in the future and Consumers should continue to receive similar amounts. 9 Tr 1991-1992; Exhibit S-3, C5, line 14, column d; Exhibit S-11.22; Exhibit S-11.23, page 4.

5. Information Technology/Business Technology Solutions-related O&M Expense

According to Mr. Varvatos, the company's projected information technology/business technology solutions (IT/BTS)-related O&M expense is $41,411,000, which is based on the 2013 actual amount of $36.3 million, and then adjusted for known and measurable changes.

The Attorney General objected and requested that the Commission approve a $1.7 million reduction because there is uncertainty as to whether Consumers will actually spend the requested money during the test year and many of the company's new software projects "are of questionable economic benefit to customers." Attorney General's initial brief, p. 18.

In its reply brief on pages 105-106, Consumers responded that "There is no explanation as to why the Attorney General is making this recommendation. Nor does the Attorney General cite to any record evidence to further his claim." Consumers stated that it provided a thorough and comprehensive review of its IT/BTS O&M expenses through the testimony of Mr. Varvatos.

The ALJ agreed that the Attorney General provided no explanation for his proposed reduction, and recommended that the Commission approve Consumers' IT/BTS-related expense. Citing the record, the ALJ stated that "the record contains ample support for the expense level suggested by the company." PFD, p. 118-119, citing 6 Tr 840-841.

No party filed exceptions on this issue, and the Commission adopts the findings and recommendations of the ALJ.

6. Pension and Benefit Operations and Maintenance Expense (Including Supplemental Retirement)

Consumers projected a total O&M expense of $73,255,000 for employee benefits. Consumers' witness, Herbert B. Kops, Director of Employee Benefits, provided a summary and an historical overview of each plan, and testified about the method in which the expense was calculated. Mr. Kops stated that the pension and benefit plans are necessary to attract and retain qualified and talented employees and executives.

The Staff noted that, "In the past decade, the Commission has not included SERP or DC SERP expenses as a component of the revenue requirement in any rate case." Staff's initial brief, p. 88. Citing several Commission decisions on this specific issue, the Staff asserted that the Commission has found that these types of plan expenses are not commensurate with benefits to ratepayers, and rather, provide benefits in the form of higher share prices and dividends to investors. *Id.*, pp. 88-89. During his testimony, Mr. Nichols quoted from page 41 of CMS Energy's 2015 proxy statement filed with the Securities Exchange Commission, which states that "these plans '…assist in the retention of our senior executives since benefits increase for each year that these executives remain employed by us and continue their work on behalf of our shareholders.'" *Id.*, p. 89, citing 9 Tr 1991. The Staff recommended a disallowance of Consumers' DB SERP expense of $4,588,000 and DC SERP expense of $159,000.

The Attorney General agreed with the Staff and requested that the Commission reject $4.7 million of Consumers' employee compensation benefits. Mr. Coppola stated that, according to the company's data, only "241 current and former executive-level employees participated in these plans as of the end of 2014," and that "It is important to note that the Internal Revenue Code limitations on funding these additional payments within the qualified retirement plans were enacted because legislators wanted to limit the cost to taxpayers of benefits which benefitted only a limited number of high income executives." 10 Tr 2301-2302. As a result, Mr. Coppola asserted, "The Commission has been very consistent in disallowing recovery of cost for non-qualified benefit plans that benefit executive level employees." *Id.*, p. 2301.

Consumers responded that the Staff misunderstands what the DB SERP and DC SERP benefits actually do. According to the company, "These expenses are directly related to retirement plans for management personnel. These are common benefit offerings, and the purpose for these benefit plans is not to earn money for investors. 8 Tr 1447, 1487. The purpose of the DB SERP and DC SERP plans are to assist the Company in attracting, retaining, and motivating management personnel." Consumers' reply brief, p. 92. Consumers argued that its management is "intrinsically involved" in the company's day-to-day activities, and the daily decisions made by management impact and benefit customers. *Id.*, p. 93. Consumers added that management makes decisions involving workforce and expense items, system reliability, customer service, and the information presented on a customer's bill.

In addition, Consumers stated that the reasons given by the Commission for disallowing the DB SERP expense in the December 22, 2005 order in Case No. U-14347 no longer exist (December 22 order). In Case No. U-14347, the Staff presented the argument (which was ultimately adopted by the Commission) that as opposed to recovering DB SERP expenses, "the Company should be improving its financial position, service reliability, and safety." Consumers' reply brief, p. 94. Consumers asserted that, compared to 2003, it is in a more positive financial situation, is continually making improvements to the reliability of its distribution system, and has demonstrated improvement in the recent five-year trends for SAIFI, the customer average interruption duration index, and the system average interruption duration index.

Consumers argued that the Attorney General made only one reference to his proposed employee benefit reduction, which was a small notation in a table on page 10 of his initial brief. In Consumers' opinion, without any further discussion or analysis of his position, the Commission should consider the Attorney General's argument "abandoned." Consumers' reply brief, pp. 101-102.

The ALJ was not persuaded by Consumers' arguments, and recommended that the Commission disallow $4,747,000 in SERP. The ALJ stated that, "Neither regulatory history nor the record assembled in this case support the utility's request to include the costs of its SERP programs as part of the recoverable expenses in this case." PFD, p. 121. Citing several rate case orders, beginning with the December 22 order, the ALJ noted that the Commission has consistently disallowed recovery of SERP-related expenses for the reason that the cost to ratepayers is disproportionate to the benefits. The ALJ asserted that after a careful examination of Consumers' SERP plans, he determined that they were substantially the same as those rejected by previous Commission orders, and therefore, suggested that the Commission adopt the Staff's and the Attorney General's proposals to remove $4.7 million from Consumers' projected Pension and Benefit O&M expense.

Consumers excepts to the ALJ's recommendation and argues that "These expenses are related to common benefit offerings and are nothing more than retirement expenses for the Company's management personnel." Consumers' exceptions, p. 45. The company asserts that the ALJ failed to acknowledge the changed circumstances since the December 22 order, and because Consumers is in a better financial position than it was in 2003, the Commission should approve recovery of the DB SERP and DC SERP expenses to allow the company to hire and retain well-qualified and effective management, ultimately to the benefit of ratepayers.

In substantial agreement with the ALJ's analysis and reasoning, the Commission adopts the Staff's proposed DB SERP and DC SERP disallowances. A review of the record shows that, similar to Consumers' past requests for SERP, the benefits to ratepayers are not commensurate with the costs. Unlike the short-term employee incentive compensation program discussed below, the Commission is able to identify few, if any, metrics for DB SERP and DC SERP that are tied to ratepayer benefits. Consumers is advised to provide metrics quantifying the benefits to ratepayers in future filings. In addition, the Commission recommends that Consumers provide additional well-defined evidentiary support demonstrating that the company's total compensation (historical and test year) are, in fact, reasonable compared to peer organizations.

7. Employee Incentive Compensation Program Costs

Consumers proposed recovery of $12,807,000 for its employee incentive compensation program (EICP) expenses and its long-term incentive plan, which applies to all non-union company employees, with the exception of its top six officers. The company explained that the EICP is a short-term program that provides rewards in the form of cash bonuses for employee achievement during the course of one year or less; the long-term incentive program provides rewards in the form of restricted stocks for good employee performance during the course of one year or more.

Consumers' witness, Amy Conrad, Director of Competition, testified that the EICP is structured so that 50% "of employee's incentive will be based on achievement of operational and performance measures for safety, reliability, and customer value" and the other 50% "will be based on the achievement of two financial measures, earnings per share ("EPS") and operating cash flow." 7 Tr 1146. She then stated that, "The long-term incentive award is an equity-based plan that involves issuance of restricted stock with a three-year cycle period. The long-term incentive plan has two components – a performance component (75.0 percent) and tenure component (25.0 percent)." *Id.* Consumers' Utility Metrics Director, R. Michael Stuart, testified that the company examined five metrics associated with the EICP: employee safety, distribution reliability, generation reliability, first time quality improvement, and productivity improvement.

According to the company, both the EICP and long-term incentive compensation are necessary to attract, retain, and motivate qualified employees. Consumers asserted that, "As a component of reasonable, market-based employee compensation, the incentive compensation costs are reasonable costs of doing business to provide utility service. Neither the EICP nor the long-term incentive plan is a bonus or profit-sharing mechanism." Consumers' initial brief, p. 130. In addition, Consumers contended that customers "benefit from a financially sound utility" that "is able to raise capital, at the best available rates," which in turn "leads to reduced costs of capital, and lower costs for customers." *Id.*, p. 131.

The Staff opposed Consumers' EICP and long-term incentive expenses. Again, the Staff noted that the Commission has disallowed incentive compensation expenses in every rate case issued in the past decade for two reasons: (1) "incentive compensation plans that were tied to Company earnings and cash flow were financial considerations that largely benefit shareholders and should not be paid for by ratepayers;" and (2) "utilities must quantify the benefits to ratepayers of employee incentive compensation plans that are tied to non-financial metrics and demonstrate that the benefits to customers of such plans outweigh the costs." Staff's initial brief, p. 91, citing the December 23, 2008 order in Case No. U-15244, p. 38.

The Staff also cited Consumers' record evidence that its incentive compensation plan was designed to align the interests of executives with those of shareholders. 9 Tr 1989. Mr. Nichols stated that, "Page 41 of CMS Energy's 2015 proxy statement filed with the Securities and Exchange Commission states that '…the equity plan is performance-based and variable and is designed to align the interests of Named Executive Officers with our shareholders.'" *Id.* The Staff argued that Consumers has not sufficiently addressed the Commission's prior concerns and reasons for disallowing incentive compensation expenses, and therefore, recommended that the Commission reject Consumers' projected EICP and long-term incentive costs.

ABATE, the Attorney General, and MEC/NRDC agreed with the Staff. The Attorney General stated that, "The Company unsuccessfully argues that it must pay a competitive compensation package to retain talented management and employees," however "it does not mean that customers should pay for all or most of that expense. Shareholders also significantly benefit from talented management, perhaps even more than customers." Attorney General's initial brief, p. 21. According to the Attorney General, Consumers did not provide sufficient evidence showing that the incentive compensation plans create significant benefits to customers so that they may be considered reasonable and prudent expenses, recoverable in rates. MEC/NRDC expressed a similar opinion:

> In this case, Consumers proposes to use financial measures but is unable to explain how those benefit customers, other than promoting the financial health of the company in the most general sense. Three of the operational performance measures track improvement in areas where the company also seeks approval of large capital and O&M expenditures to achieve the same outcomes, rendering it impossible to attribute any resulting improvements to employee motivation as opposed to program funding. The other two measures are outlined in a vague and non-transparent way, and discovery for more specifics revealed none. Consumers has offered no reason for the Commission to depart from long-standing precedent on this issue.

MEC/NRDC's initial brief, pp. 53-54.

While Energy Michigan did not advocate for or against Consumers' EICP, it requested that the Commission make several modifications to the proposed expenses. Energy Michigan noted that "50% of the incentive payout is tied to financial goals that benefit shareholders and not customers," and suggested that there be "a shared benefit based on these goals, [and] that share should come from the increased shareholder earnings and not from customer rates." Energy Michigan's initial brief, p. 4. In addition, Energy Michigan stated that Consumers failed to separate distribution service benefits from power supply service benefits. As a remedy, Energy Michigan proposed that "in accordance with the cost-of-service principle of assigning costs to the customers that receive the benefits, ROA customers should be charged only for those incentive program costs that benefit distribution-only customers, and not for those that benefit power supply customers." *Id.* Energy Michigan argued that these modifications "will better align the proposed program with true cost of service, in accordance with MCL 460.11(1)." *Id.*, p. 3.

Like the Staff and the Attorney General, the ALJ noted that the Commission has not approved EICP expenses in a rate case for the last 10 years. The ALJ concluded that, yet again, Consumers failed to meet its burden to show that the payment of such incentives benefits ratepayers. According to the ALJ, "an astoundingly large percentage of the total incentive payments to be provided under the utility's short- and long-term EICP components are inextricably tied to shareholder-focused financial performance targets (such as EPS, operating cash flow, relative shareholder return, and relative EPS growth), which provide little--if any--benefit to Consumers' ratepayers." PFD, p. 127. In addition, the ALJ found that MEC/NRDC noted, "the metrics assigned by the utility to determine whether an employee is deserving of an incentive (whether by cash bonus or the receipt of restricted stock) rest almost exclusively on areas where the company already plans to expend a large amount of capital investment and/or O&M expense to achieve the same goals as offered in support of its EICP." *Id.* Finally, the ALJ argued, the metrics supporting Consumers' proposed EICP are too vague to justify Commission approval of $12,807,000. Therefore, the ALJ recommended rejecting Consumers' proposed EICP expenses.

In its exceptions, Consumers asserts that contrary to the ALJ's finding, the Commission's standard for recovery of incentive compensation plans set forth in the December 22 order does not wholly apply to its EICP. According to the company, the EICP expenses "are not bonus plans or profit-sharing plans," because "employees are not paid in excess of market rates when they receive incentive compensation under the EICP; rather, they are paid below market rates if they do not receive incentive compensation." Consumers' exceptions, p. 48. Consumers reiterates that its costs are reasonable and necessary to attract, retain, and motivate its employees, benefitting ratepayers.

Although the ALJ determined that Consumers already plans to spend a large amount of capital investment and/or O&M expense to reach the same goals as offered in support of its EICP, the company disagrees. Consumers' exceptions, p. 53. Consumers states that:

> The fact that some of the investments and O&M expenses described by the Company in this case are designed to result in improvements in the same categories of operational performance measures included in the EICP metrics does not undermine the importance of the incentive compensations programs to focus and motivate employees toward achievement of the performance goals.

Id. Consumers adds that the incentive compensation plans "complement, not duplicate, improvements in the operational areas of safety, distribution reliability, and generation reliability." *Id.*, p. 54. The company restates that the EICP is reasonable, consistent with industry practice and standards, and without charging additional costs to ratepayers, it embodies the best method for emphasizing customer focus through compensation design. *Id.*, p. 56. As a result, Consumers requests that the Commission approve its EICP expenses.

On page 10 of its replies to exceptions, MEC/NRDC assert that Consumers' exceptions lack merit because the company failed to "demonstrate a sufficient causal connection between the incentive program and customer benefits." MEC/NRDC state that "Consumers never disputes that the EICP is heavily weighted toward financial metrics," fails to demonstrate that the benefits are commensurate with the costs, and that the EICP metrics are so vague, they cannot be evaluated.

Over the past 10 years, the Commission has rejected Consumers' proposed EICP expenses because the company failed to demonstrate that the costs to ratepayers correspond with the benefits. However, in the immediate case, the Commission finds that Consumers provided convincing evidence that the proposed $5.3 million for the short-term EICP provides appreciable benefits to customers, and meets the standard set forth in the December 22 order. *See,* 7 Tr 1168-

1181. Consumers' witness, Ms. Conrad, gave extensive testimony regarding the structure and function of the short-term EICP, and in discussing ratepayer benefits, she stated that:

> Shifting a portion of employees' reasonable, market-based compensation to an incentive based component benefits customers without additional cost. The incentive-based "carve-out" of the Company's reasonable costs of employee compensation puts a portion of employees' pay at risk unless the performance targets are achieved. 7 Tr 1177. The Company's performance based incentives provide concrete incentives to accomplish specific goals that represent performance priorities for Consumers Energy and its customers. 7 Tr 1177. The incentive plans help create a culture of performance, rather than entitlement.

Consumers' initial brief, p. 131. In addition, Consumers was able to quantify the benefits to ratepayers through five metrics: employee safety, distribution reliability, generation reliability, first time quality improvement, and productivity improvement. *See,* 6 Tr 913-915. Therefore, the Commission approves the recovery of $5.3 million for Consumers' short-term EICP.

However, regarding the long-term incentive compensation, the Commission finds that the company failed to demonstrate that the benefits to ratepayers are commensurate with the costs. Consumers' long-term incentive compensation is tied closely to company earnings and cash flow measurements that overwhelmingly benefit shareholders. *See*, 7 Tr 1146-1147 and 9 Tr 1988. Consequently, the Commission finds, Consumers' long-term incentive compensation does not meet the criteria set forth in the December 22 order and is rejected.

Finally, it should be noted that Energy Michigan did not file exceptions or replies, and therefore the Commission declines to address its proposed changes to Consumers' EICP.

8. Advance Metering Infrastructure Operating & Maintenance Expense

Consumers requested $14,238,000 in O&M expenses for the AMI program. The ALJ stated that the Staff was the only party to dispute the company's AMI expenses. However, the ALJ noted that "the Staff's two areas of dispute relate to issues that have already been resolved in the utility's favor (namely, the company's continued used of DLA switches, as well as the utility's reliance on projected test year O&M figures instead of those set forth in the January 2015 Budget)." PFD, pp. 128-129. Therefore, the ALJ determined that based on the record and his previous findings regarding the AMI program and the company's proposed 2015-2016 spending, Consumers' projected AMI O&M expenses should be approved.

No party filed exceptions on this issue, and the Commission adopts the findings and recommendations of the ALJ.

9. Uncollectible Accounts Expense

Consumers estimated that its Uncollectible Accounts expense for the test year is $30.799 million. Consumers' witness, Daniel L. Harry, Director of Accounting Process and Control, testified that the Uncollectible Accounts expense is comprised of: "(1) the write-off of customer accounts receivable balances that are deemed uncollectible; and (2) changes during the period in the uncollectible reserve account." Consumers' initial brief, p. 138, citing 6 Tr 648. Mr. Harry also explained that Consumers calculated the Uncollectible Accounts expense by subtracting amounts associated with the uncollectible tracker expense and PeopleCare. Then, a ratio of three-year average bad debt loss of uncollectible accounts expense and electric service revenue for the years 2011-2013, is applied to test year electric service, along with surcharge revenue, to arrive at the projected test year Uncollectible Accounts expense. *Id.*, pp. 138-139. Mr. Harry justified using a three-year average by stating that "Test year electric uncollectible expense is largely impacted by the economy as well as fuel and purchased power cost prices," and "Therefore, using a three-year average BDLR [bad debt loss ratio] approach in this case provides a reasonable estimate of future uncollectible accounts expense." 6 Tr 649.

The Staff recommended reducing Consumers' uncollectible accounts expense by $6,940,000 to align the company's projected expenses with those presented in the January 2015 budget to the

Board of Directors. Mr. Nichols argued that "his analysis included a review of the Company's filed projection, based on historical averages, presentations made to investors, and the amounts in the budget." Staff's initial brief, p. 75.

On page 19 of his initial brief, the Attorney General asserts that Consumers' method of calculation is "too simplistic and results in an inaccurate forecast." Instead, the Attorney General recommended "[a] better approach," which calculates, over multiple years, the ratio of uncollectible accounts' write-offs to revenues. *Id.* Then, he asserted, the "resulting average ratio can…be applied to forecasted test year revenues to determine an appropriate forecast of uncollectible accounts." *Id.* Mr. Coppola chose a five-year period, which he asserted contains a better estimate of high and low years of uncollectible expenses, and concluded that the uncollectible accounts expense should be $25.3 million.

The ALJ agreed with the Attorney General and recommended that the Commission adopt his uncollectible accounts expense calculation and $5.5 million reduction. He pointed out that Consumers and the Attorney General both agree that:

> the company's actual level of uncollectible accounts expense can vary significantly from year to year based on myriad outside factors. As a result, unless some significant aberration can be identified as causing one year's expense level to be so skewed as to require viewing that year as an outlier…it would appear that, of two relatively similar periods, the one that is slightly longer would generally serve to provide the better estimate.

PFD, p. 131.

Consumers objects to the ALJ's recommendation and states that the Attorney General's proposed $5.5 million reduction fails to project a reasonable uncollectible accounts expense. In Consumers' opinion, "Mr. Coppola's calculation dilutes the recent trend of higher uncollectible expense," and "[t]he Company's projection at $30.8 million is more reflective of the Company's recent uncollectible expense experience over the 2012 through 2014 timeframe." Consumers' exceptions, p. 43.

The Commission agrees with the ALJ and finds that the Attorney General's proposed five-year average of uncollectible accounts expense, which uses a longer period over which to average the expense, provides a better estimate of the company's expected uncollectible accounts expense. In addition, the Attorney General provided a more persuasive and detailed calculation of uncollectible accounts expense, and as a result, the Commission finds that an uncollectible expense of $25.3 million should be approved.

10. Depreciation and Amortization Expense

The ALJ noted that Consumers' figures in this rate case filing were based, in part, on depreciation rates approved in Case No. U-16054. However the May 14 order established new depreciation rates and directed that they be applied to this case. Consumers' witness, Natalie N. Busack, Senior Rate Analyst in Consumers' Revenue Requirements Section, updated the company's requested rates pursuant to the May 14 order. The Staff agreed. As a result, the ALJ recommended that the Commission approve Consumers' updated depreciation and amortization expense.

No party filed exceptions on this issue, and the Commission adopts the findings and recommendations of the ALJ.

11. Tax Expense and Allowance for Funds Used During Construction

According to the ALJ, no party objected to Consumers' projected test year property tax or the company's proposed Allowance for Funds Used During Construction-related costs. The Staff suggested that Consumers increase its projected federal, state, and local income tax expense, and the company agreed. Therefore, the ALJ found "these agreed-to expense levels [to be] reasonable, and thus recommends the corresponding figures set forth in Appendix C of the company's initial brief to be adopted by the Commission." PFD, p. 133.

No party filed exceptions on this issue, and the Commission adopts the findings and recommendations of the ALJ.

C. Calculation of Adjusted NOI

In summary, the Commission finds that Consumers' jurisdictional projected NOI for the 2015-2016 test year is $486,658,000.

VI. OTHER REVENUE AND ACCOUNTING ISSUES

A. Consumers' Proposed Revenue Adjustment Mechanism

Consumers' witness, Laura M. Collins, a Senior Rate Analyst in the Pricing Section of the Rates Department, testified that the company is requesting a RAM "because sales and associated revenues are difficult to predict and highly volatile due to economic conditions, electric choice migration, and weather." 5 Tr 562. In her opinion, the RAM will assist Consumers in collecting the level of revenues that are approved by the Commission. 5 Tr 563. Consumers' request for an RAM is conditioned on the enactment of currently pending legislation permitting electric revenue adjustment mechanisms. Addressing this condition, Ms. Collins provided a detailed description of the company's proposed RAM and reconciliation procedures, set forth on pages 145-146 of its initial brief, citing 5 Tr 563-566, which will not be repeated here.

ABATE, the Attorney General, Hemlock, Kroger, and the Staff argued that Consumers' proposed electric RAM is illegal and should be rejected. Furthermore, even if the RAM is not contrary to Michigan law, Energy Michigan, the Staff, and Wal-Mart asserted that Consumers' proposed RAM "improperly transfer[s] risk to customers, [and] it would also result in rates that are not just and reasonable." Staff's initial brief, p. 102.

Only MEC/NRDC supported Consumers' proposed RAM. MEC/NRDC stated that approval of a contingent RAM "could result in substantial savings to customers if it leads to decisions on the part of Consumers to maximize the potential for cost-effective energy efficiency as part of its resource portfolio." MEC/NRDC's initial brief, p. 55.

The ALJ found that the Commission does not have the authority pursuant to Michigan law to approve Consumers' proposed RAM. The ALJ stated, "As pointed out by several parties, the Court of Appeals expressly held that there is no statutory authority for authorizing any sort of revenue decoupling mechanism (such as the RAM proposed here) for an electric utility." PFD, p. 136. Therefore, the ALJ recommended that the Commission reject Consumers' proposed RAM.

In its exceptions, Consumers asserts that the ALJ's determination is inconsistent with the company's request. The company states that it "explicitly made its request conditional on the enactment of legislation addressing revenue adjustment mechanisms for electric utilities during the pendency of this case." Consumers' exceptions, p. 57. Consumers contends that it is not requesting a RAM on a contingent basis, and insists that Commission approval of the mechanism is not beyond the scope of this proceeding. In the company's opinion, the record contains substantial evidence that supports the reasonableness of its RAM, and requests that the Commission approve its proposed RAM.

In response to the ALJ's recommendation, MEC/NRDC state that "there is a bill pending in the Legislature that would authorizing [sic] revenue decoupling," and Consumers' request "is that the Commission approve the RAM contingent upon legislation authorizing it." MEC/NRDC's exceptions, p. 15. MEC/NRDC assert that the proposed RAM and pending legislation are not hypothetical, and the ALJ provided no citation to support his determination that the Commission has no legal authority to conditionally approve a RAM. In MEC/NRDC's opinion, "The Commission should take what action is available to it on this subject now, not later." *Id.*, p. 16.

ABATE, the Attorney General, and Hemlock reiterate that the Commission does not have express statutory authority to approve a RAM for electric utilities, and recommend that the exceptions filed by Consumers and MEC/NRDC be rejected.

The Commission agrees with the ALJ, ABATE, the Attorney General, Hemlock, Kroger, and the Staff that the Commission does not have the authority to approve Consumers' proposed RAM. Although there may be a bill pending in the legislature that would permit Consumers to implement the RAM, the Commission notes that as of the date of this order, the bill has not been signed by Governor Snyder, is not current law, and therefore, does not apply to Consumers' proposed RAM. As a result, the Commission is restricted by existing law, and as stated by the Michigan Court of Appeals, there is no statute that "empower[s] the PSC to approve or direct the use of an RDM [revenue decoupling mechanism] for electric providers." *See, In Re Application of Detroit Edison Co*, 296 Mich App 101, 110 (2012). Therefore, the Commission declines to adopt Consumers' proposed RAM.

B. Consumers' Investment Recovery Mechanism

Consumers requested an IRM that will assist in the recovery of 2017 and 2018 average incremental rate base and associated direct expenses beyond the level ultimately approved in the test year. Consumers' initial brief, p. 147, citing 3 Tr 329. Ms. Busack explained:

> The IRM will operate through a surcharge effective June 1, 2016 until rates are reset in a subsequent general rate case. Following the end of 2017, the Company will file the first of two reconciliations which update the initial incremental revenue requirement calculation with actual balances and determine if the actual incremental rate base is greater or less than projected amounts reflected in the surcharge rates. The IRM surcharge would be reduced to incorporate any decrease to the incremental revenue requirement.

5 Tr 329. The company proposed to collect the incremental revenue through demand and energy surcharges for each rate schedule. *Id.*, p. 567.

In response, the Attorney General, MEC/NRDC, and Hemlock argued that Consumers' proposed IRM is contrary to the plain language of MCL 460.6a(1) "because it would provide rate relief for costs incurred beyond a future consecutive 12-month period." MEC/NRDC's initial brief, p. 32-33; Hemlock's initial brief, pp. 21-22; and Attorney General's reply brief, p. 3. In addition, Hemlock asserted that the IRM is "an impermissible rate adjustment mechanism" that violates MCL 460.6a(2). Hemlock's initial brief, p. 22. MEC/NRDC contended that the Commission's decision to approve an IRM in Case No. U-16999 is clearly distinguishable from the current case, in that the Commission permitted Michigan Consolidated Gas Company to implement a much smaller, fixed, and well-defined IRM, which was initiated by the Commission and used to encourage capital investment to enhance public safety.

In addition to the legal arguments against Consumers' proposed IRM, ABATE, the Attorney General, Hemlock, Kroger, and Wal-Mart set forth several policy arguments opposing the proposed IRM, which shall not be repeated here. *See*, ABATE's initial brief, p. 13; Attorney General's initial brief, p. 13; Hemlock's initial brief, pp. 22-24; Kroger's initial brief, pp. 2-3; Wal-Mart's initial brief, p. 8; and Attorney General's reply brief, p. 3.

Consumers responded that its IRM, as a ratemaking mechanism, is lawful and reasonable, and "Based on the plain language of MCL 460.6a(1), it is incorrect to conclude that the statute only allows a utility to base its rate request on a projected test year." Consumers' reply brief, p. 116. Consumers asserted that the test year clause of MCL 460.6a(1) states that a "utility *may* use projected costs and revenues for a future consecutive 12-month period . . .." (emphasis added). The company argued that the Michigan Court of Appeals has found that the word "may" is permissive and that it indicates "a non-mandatory procedure." *Id.*, citing *Ewin v Burnham*, 272 Mich App 253, 257; 728 NW2d 463, 466 (2006). Therefore, Consumers contended that the "use of a consecutive 12-month test year does not preclude a utility from requesting and the Commission from authorizing use of an IRM to provide for recovery of costs beyond the 12-month period." *Id.* In addition, the company stated that pursuant to several statutes, the Commission has ratemaking authority which allows it to approve the proposed IRM.

In the ALJ's opinion, it is unnecessary to consider the legality of Consumers' proposed IRM or whether Case No. U-16999 is applicable to this case, because the policy arguments alone are sufficient to convince the ALJ to recommend against the proposed IRM. The ALJ stated that:

> Both the size and the scope of the IRM is nothing short of breathtaking, with its single tracking mechanism calling for substantially more in the way of rate relief (again, $242 million annually by 2018) than the utility even requested in its current general rate case. Moreover, by allowing the IRM to take effect, the Commission would--as correctly argued by numerous parties--essentially be approving a pair of single-issue rate cases, in which the rate relief requested for additional capital investment would be granted (almost automatically) with no opportunity to recognize and account for potential cost reductions arising in other areas of the utility's operations. Most importantly, the company's request that each reconciliation of its capital investments for 2017 and 2018 view those investments "at the aggregate" level, and then simply compare those figures to the corresponding levels set forth in its annual Form P-521 filings, would effectively allow Consumers to make those expenditures wherever and however it chooses. Granting such a great amount of flexibility would, particularly in light of the fact that such actions could occur without the usual fully-contested rate case proceedings designed to protect all interested parties, leave Consumers in the position where no negative repercussions would arise from spending these funds in an unreasonable and imprudent manner.

PFD, p. 141. Therefore, the ALJ found that Consumers' proposed IRM should be rejected in its entirety.

Consumers excepts and argues that the ALJ's determination "does not appropriately consider the record evidence provided by the Company." Consumers' exceptions, p. 59. According to the company, there are a number of reasons that the ALJ's policy considerations are not proper causes to reject Consumer's proposed IRM. First, for the IRM, Consumers stated there are more opportunities for Staff review and audit than there are for capital expenditures in traditional ratemaking. Second, the company notes that the proposed IRM includes an annual contested reconciliation case, "which will review actual investments compared to capital expenditure amounts projected in the IRM surcharges," and it "allows ratepayers the opportunity to only pay for those expenditures that are actually incurred by the company." *Id.* Third, Consumers disputes that the IRM unfairly shifts risks to ratepayers, and argues that instead, it reduces "the risk that customer rates will reflect costs related to investments that did not ultimately come to fruition or provide a benefit." *Id.*, p. 60.

In his replies to exceptions, the Attorney General agrees with the ALJ and reiterates that the Commission lacks statutory authority to approve the IRM, the proposed IRM violates the single-issue rate making prohibition of MCL 460.6a, and 2008 PA 286 reduces the need for trackers like the proposed IRM. ABATE, Hemlock, and MEC/NRDC agree.

The Commission agrees with the ALJ that policy considerations alone necessitate a decision declining to adopt Consumers' IRM proposal in this case. The IRM proposal appears to constitute a substantial single-issue rate case addressing a future period, without the benefit of accounting for cost reductions which will undoubtedly have occurred, or the benefit of reviewing expenditures for reasonableness and prudence. The Commission finds that the IRM proposal should be rejected.

C. Line Loss Issues

Consumers' witness, Ms. Palkovich, sponsored the company's 2013 line loss study, and testified that the study was conducted to determine the line losses, or total energy lost, through the numerous components of the company's electric distribution system. Consumers' initial brief, pp. 152-153. Consumers stated that "The 2013 Line Loss Study allocates system energy and demand losses among the various components of the system by calculating a percentage loss factor for each component." *Id.*, p. 153. According to Consumers, it updated the original line loss factors in response to a discovery question, using actual company pertinent data, which resulted in a more accurate analysis of line loss on the company's distribution system. Ms. Palkovich asserted that "The impact of this change would result in an approximate $1 million aggregate reduction in revenue requirement for Residential and Secondary customers (5 Tr 492), and would increase the revenue requirement for the Primary class by approximately $1 million." *Id.*, citing 5 Tr 491-492. Consumers requested that in the event the Commission approves the updated line loss study, the change should be reflected in the COSS, rate design, and tariffs.

While not specifically opposing Consumers' line loss study, MEC/NRDC expressed some concerns with the company's updated study. MEC/NRDC requested that the Commission set the new power supply cost recovery (PSCR) "loss factor based on the projection of line losses in the sales and load forecast, not the projection from the allocation study, because the sales and load forecast more realistically projects losses to decline in the years ahead due to a number of ongoing programs." MEC/NRDC's initial brief, p. 39. MEC/NRDC asserted that its proposal is more reasonable because: (1) the company offered no technical or engineering reason to support the use of the allocation study; (2) just as the loss factor is used in the PSCR, the loss factor from the sales and load forecast is an overall estimate for the system; and (3) while the loss factor from the sales and load forecast is expected to decline in the future based on changing conditions, the factor from the revised loss allocation study is a fixed number from 2013. *Id.*, pp. 43-44. In addition, MEC/NRDC argued that "because Ms. Palkovich agreed that Mr. Jester's loss mitigation recommendations are reasonable…the Commission should condition the inclusion of requested distribution capital expenditures on Consumers agreeing to prepare a system loss mitigation plan that evaluates the costs and benefits of available measures." *Id.*, p. 45.

Energy Michigan asserted that following the updated line loss study, it was expected that Consumers would update the COSS, including proposed rate designs, but has failed to do so. Consequently, Energy Michigan requested that “the Commission defer acceptance of the new line loss study to a future proceeding, where Consumers will have the opportunity on the record to offer its justification for the study and to explain how it will affect customer rates.” Energy Michigan’s initial brief, p. 11.

In response to MEC/NRDC, Consumers stated it would be unreasonable to use the sales and load forecast’s loss factor because this factor does not reflect current system losses. Additionally, “the impact of AMI theft reduction, peak pricing, dynamic peak pricing, and DLA on line loss would need to be removed.” Consumers’ reply brief, p. 124. Finally, Consumers contended that the line loss factor used in the sales and load forecast cannot be used to develop rates because it is too vague.

The ALJ was not persuaded by MEC/NRDC’s arguments for several reasons. First, the ALJ stated that MEC/NRDC’s allegation that Consumers failed to provide witness and evidentiary support for its decision to use the updated line loss study to set the PSCR factor is not accurate. The ALJ noted that Consumers’ witnesses who testified on this issue were never specifically asked about using the sales and load forecast to set the PSCR loss factor. PFD, p. 144. Second, ALJ found it unreasonable for the Commission to use the sales and load forecast’s loss factor because:

> (1) it does not reflect current system losses, (2) the effect of AMI theft reduction, peak pricing, dynamic peak pricing, and the DLA program would apparently have to be removed because those adjustments were made by Consumers in order to forecast sales, not to depict line losses, and (3) the line loss factor in the sales and load forecast is not adequately detailed for use by the utility’s Rates Department, which needs losses to be determined and allocated by voltage level.

Id. And lastly, the ALJ stated that contrary to MEC/NRDC's proposal, "the record does not support making approval of the company's distribution capital expenditures contingent upon its agreement to prepare a system loss mitigation plan." *Id.*

Regarding Energy Michigan's proposal, the ALJ also disagreed. The ALJ stated that Consumers provided all of the parties with an updated COSS, which included all of the corresponding rate impacts. The ALJ noted that the Staff used the updated line loss study to prepare the COSS and rate design. In addition, the ALJ found that the "compliance filing that Energy Michigan seeks in return for using the results of the updated study is unnecessary." PFD, p. 145. Therefore, the ALJ recommended that the Commission approve the results of the revised line loss study prepared by Consumers to be used to update the COSS, rates, and tariffs.

In its exceptions, MEC/NRDC disagree with the ALJ's finding that none of Consumers' four witnesses were specifically asked about using the sales and load forecast to set the PSCR loss factor. MEC/NRDC assert that the ALJ's determination is "not an accurate reflection of the record," and provides several examples in the testimony where it feels the ALJ's conclusion is incorrect. MEC/NRDC's exceptions, p. 8. MEC/NRDC also except to the ALJ's finding that the sales and load forecast loss factor "does not reflect current system losses." MEC/NRDC's exceptions, p. 10, citing the PFD, p. 144. MEC/NRDC argue that "the sales and load forecast loss factor reflects more timely information going forward," whereas the "line loss study represents a singular snapshot of historic data from 2013." *Id.* In MEC/NRDC's opinion, even if the line loss study is current, using it to set the PSCR loss factor would inflate future losses and PSCR costs, which cannot be changed until Consumers conducts a new line loss study in a future rate case. MEC/NRDC also object to the ALJ's reasoning that AMI theft reduction, peak pricing, dynamic peak pricing, and the DLA program would have to be removed because the determination seems to be taken almost word-for-word from Consumers' reply brief and contains no citation to the record.

In response to the ALJ's determination that the line loss factor in the sales and load forecast is not adequately detailed for use by Consumers' Rates Department, MEC/NRDC states that the ALJ misunderstood its argument. MEC/NRDC are not proposing to use the estimate of losses in the sales forecast to set rates. Instead, MEC/NRDC are suggesting that the estimate "be used to set the multiplier applied to the PSCR factor to determine total PSCR costs for a plan year." MEC/NRDC's exceptions, p. 12.

Finally, MEC/NRDC except to the ALJ's finding that the record does not support requiring Consumers to submit a loss mitigation plan. MEC/NRDC disagree with the ALJ that it was recommending "that Consumers needed to achieve a pre-determined outcome with respect to loss reduction, let alone an outcome that defied practical limits or the laws of physics." MEC/NRDC's exceptions, p. 13. Rather, MEC/NRDC is proposing a "loss-reduction plan as a condition of the approval of distribution capital expenditures that Consumers predicts will have loss-reduction benefits." *Id.* In MEC/NRDC's opinion, without a loss mitigation plan and Commission follow-up, it is not likely that the losses will show the steady progress predicted by the forecast group, or that the PSCR loss multiplier will be updated in the near future to reflect declines in losses, if they do decline. *Id.*, p. 14.

In its replies to exceptions, Consumers argues that MEC/NRDC is recommending an outdated sales and load forecast line loss factor that is not based on an actual line loss study. Consumers' replies to exceptions, p. 62. What is more, the company asserts, MEC/NRDC's proposed line loss factor contradicts its previous request in Case No. U-17095 for approval of a new line loss factor based on more current information. Consumers also reiterates that "None of the Company witnesses testified to using the sales and load forecast's loss projection to set the PSCR loss factor, and in fact, the Company witnesses were never asked whether the PSCR loss factor should be set utilizing the sales and load forecast's loss projection." *Id.*, p. 63. Because MEC/NRDC proposed using the sales and load forecast's loss factor, Consumers contends that they have the burden of proving the reasonableness of utilizing the sales and load forecast's loss factor and MEC/NRDC have failed to do so.

In response to MEC/NRDC's exception regarding its proposed system loss mitigation plan, Consumers states the proposed plan is unnecessary because the company reasonably addresses system line loss with activities geared toward evaluation and mitigation, and is continuing to explore methods that will help reduce line loss. Consumers' replies to exceptions, p. 65.

The Commission finds Consumers' updated line loss study to be reasonable and prudent. Like the ALJ's determination, the Commission believes that Consumers' witnesses provided sufficient testimony and evidence to support its decision to use the updated line loss study to set the PSCR factor. *See*, 5 Tr 585-586; 6 Tr 788-791; 8 Tr 1372-1414. In addition, the Commission agrees with Consumers and the ALJ that it is unreasonable to use MEC/NRDC's proposed sales and load forecast's loss factor for several reasons. First, it does not reflect current system losses because the information used to develop the factor is about 10 years old. Second, the effect of AMI theft reduction, peak pricing, dynamic peak pricing, and the DLA program would need to be removed because those adjustments were made by Consumers in order to forecast sales, not to depict line losses. Third, the line loss factor in the sales and load forecast is not adequately detailed for use by the utility's Rates Department, which needs losses to be determined and allocated by voltage level. The Commission also agrees with the ALJ that the record does not support making approval of Consumers' distribution capital expenditures contingent upon its agreement to prepare a system loss mitigation plan. Therefore, the Commission declines to approve MEC/NRDC's proposals to adopt the sales and load forecast's line loss factor and the system loss mitigation plan.

Notwithstanding, the Commission recognizes the importance of understanding potential opportunities to reduce energy waste through the mitigation of line losses in the event such opportunities are cost-effective relative to other investments. Given that the functioning of the grid and replacement of aging distribution infrastructure will likely be of ever increasing importance in the coming years with the advent of emerging technologies, the Commission finds it is important to examine distribution planning in a holistic manner and base investment decisions on strong analytical support of the costs and benefits. The Commission therefore directs the Staff to engage with stakeholders on the process going forward, to educate and enhance understanding of this complex issue.

For the reasons set forth by the ALJ, the Commission also rejects Energy Michigan's proposal to defer acceptance of the new line loss study to a future proceeding.

VII. REVENUE DEFICIENCY SUMMARY

Pursuant to his findings and calculations in the PFD, the ALJ determined that Consumers' approximate revenue deficiency for the test year is $111,498,000.

Consumers excepts to the ALJ's calculation of the revenue deficiency, stating that "the recommendations in the PFD substantially understate the reasonable and appropriate revenue requirement for Consumers Energy's electric business." Consumers' exceptions, p. 60.

The Municipal Coalition also excepts, noting that Consumers proposed a rate increase of $196.7 million ($162.7 million, plus the $34 million for depreciation changes), however, "the Attorney General's expert witness could only find a revenue deficiency of $16.6 million prior to considering the depreciation expense," and the "Staff found only an approximate increase of $26 million prior to depreciation." Municipal Coalition's exceptions, p. 2. According to the Municipal Coalition, the Attorney General and the Staff are only able to verify 10% to 15% of Consumers' base rate request.

Applying the same method to the ALJ's calculation, the Municipal Coalition argues that the ALJ's finding of a $111.5 million revenue deficiency is still much higher than what can be verified. Of the $111.5 million, the Municipal Coalition states that "only 15% can be verified by the Attorney General, and only 25% can be verified by Staff." Municipal Coalition's exceptions, p. 2. And, whether it is coincidental or not, the Municipal Coalition notes that the $111.5 million is almost exactly between Consumers' proposed revenue deficiency and the Staff's. Thus, the Municipal Coalition believes that the ALJ's recommendation "seems to be based more on splitting the difference between Consumers and Staff than on a thorough assessment of the evidence presented." *Id.*, p. 3. The Municipal Coalition asserts that Consumers has not demonstrated with sufficient evidence that a $162.7 million increase in base rates is necessary.

Consumers disputes the Municipal Coalition's calculation of the revenue deficiency, and on p. 89 of its replies to exceptions, the company argues, "The Municipal Coalition cites to the revenue recommendations of Staff and the Attorney General, but does not offer any argument or analysis about why the evidence in this case should result in a lower overall revenue recommendation." Consumers states:

> Rule 435(3) of the Administrative Hearing System's Rules of Practice and Procedure before the Commission, 2015 MR 1; R 792.10435(3), states: "Exceptions . . . shall be supported by reasoned discussion of the evidence and the law. Exceptions. . . containing factual allegations claimed to be established by the evidence shall include a reference to the specific portions of the record where the evidence may be found. . . ."

Id. In the company's opinion, the Municipal Coalition's provides no argument or analysis in support of its request, the request is conclusory in nature, and it should be rejected by the Commission.

The Commission agrees with Consumers that the Municipal Coalition failed to set forth any persuasive argument or analysis in support of its request. The Municipal Coalition cited the Attorney General's and the Staff's calculations for the revenue deficiency, but did not provide any analysis as to how the Attorney General's or the Staff's calculations were superior to Consumers'. Therefore, pursuant to Rule 453(3), the Commission finds that the Municipal Coalition's exception on this issue should be rejected.

In accordance with the foregoing findings, Consumers' jurisdictional revenue deficiency (reflecting the updated depreciation amounts) for the test year is computed as follows:

Rate Base	$9,160,088,000
Overall Rate of Return	6.1808%
Income Required	$566,166,000
Adjusted Net Operating Income	$486,658,000
Income Deficiency	$79,508,000
Revenue Conversion Factor	1.6367
Revenue Deficiency excluding Jackson Plant and including Classic 7 O&M	$130,127,000
Add:	
Jackson Gas Plant Revenue Requirement	$34,685,000
Revenue Deficiency including Jackson Gas Plant and including Classic 7 O&M	$164,812,000
Remove:	
Classic 7 Revenue Requirement	$(38,455,000)
Total Revenue Deficiency including Jackson Plant & excluding Classic 7 O&M	$126,356,000

VIII. COST OF SERVICE

On June 30, 2015, pursuant to 2014 PA 169, the Commission issued an order (June 30 order) in Case No. U-17688, in which, *inter alia*, it approved a proposal to modify the then-existing four coincident peak (4CP) 50-25-25 method of production cost allocation to 4CP 75-0-25, finding that this method better assures that rates are equal to cost of service. In addition, the Commission approved the allocation of transmission costs based on 12CP 100-0-0, and it addressed a number of rate design proposals, some of which were deferred to this case and are discussed in more detail below. Although there was some additional dispute in this proceeding over production cost allocation and the functionalization or assignment of uncollectibles and other customer-related costs, Consumers and most other parties in this case agreed that, in light of how recently the June 30 order was issued, there was no compelling reason to revisit the matters decided by that order. The ALJ concurred, finding:

> Because the extensive Commission decision rejecting each of these parties' now-renewed arguments was issued less than 10 weeks ago, and because the parties have not shown that some significant change has occurred since the issuance of the June 30 order, the ALJ finds that the Commission's recent ruling on each of those matters should be applied in this case, and thus recommends that the particular positions taken (or, renewed, as it were) on these issues be rejected again.

PFD, p. 150.

Hemlock takes exception, arguing that although the Commission recently approved a 4CP 75-0-25 production cost allocation method, the ALJ erred in failing to undertake an independent analysis of the evidence presented in this case, which clearly shows that a 4CP 100 production cost allocator most accurately and appropriately reflects cost-causation principles, and it comports with the Energy Intensive Industrial Rates (EIIR) Workgroup recommendation. Hemlock contends that the June 30 order was wrongly decided, arguing that "the Commission's finding [approving 4CP 75-0-25] reflects the Commission's assessment of the practical implications of adopting a 4 CP 100% demand production cost allocator[,]" and that "[t]he Commission's ruling is inconsistent with the consensus proposal put forth by a wide array of interests reached over months of deliberations [i.e., the EIIR Workgroup report]." Hemlock's exceptions, p. 5. Hemlock therefore urges the Commission to reject the PFD and adopt a 100% demand production cost allocator.

The Commission agrees with the ALJ and finds that there was no error in his analysis or his recommendations. The Commission further observes that although Hemlock, in part, contends that there was new evidence introduced in this proceeding that better supports a 4CP 100 production cost allocator, a review of Hemlock's presentation in this case differs little, if at all, from the evidence and arguments that it presented in Case No. U-17688. In addition, as the ALJ observed, Hemlock points to no change with respect to electric generation or production costs in the few months since the June 30 order was issued that would support a change in the cost allocation method approved in that proceeding. Hemlock's exception is therefore rejected and the Commission again approves the use of 4CP 75-0-25 for the production cost allocator.

IX. RATE DESIGN AND OTHER TARIFF ISSUES[9]

A. Direct Load Management and Dynamic Peak Pricing Tariffs

Under Consumers' current pilot direct load management (DLM) tariff, the company is permitted to cycle participants' air conditioning off only during certain peak times of the day. In this case, Consumers proposed removing the time limits on DLM, allowing cycling at any time. The Staff objected, arguing that the pricing under the DLM tariff essentially removes on-peak costs; thus the complete removal of the time limitations was inappropriate under the current tariff pricing. The Staff further recommended that the company, in its next rate case, provide a calculation of the DLM credit consistent with its benefits. In response, Consumers argued that limiting the operation of the program to peak-times only, as the Staff suggested, would result in the disqualification of the program as a load modifying resource (LMR) under the Mid-Continent Independent Operating System, LLC's (MISO's) LMR program. The Staff countered that even if the DLM program did not qualify as an LMR, there are still benefits to the program because the company can use DLM to avoid high-cost energy or capacity purchases during peak periods.

The ALJ agreed with the Staff that even if the DLM program does not currently qualify as an LMR, there are nevertheless benefits to the program for both participants and the company. The

[9] Minor tariff changes that were not disputed by the parties, and not addressed in the PFD or exceptions, are approved.

ALJ specifically concurred with the Staff's point that the program can still be used to reduce the need for expensive energy that Consumers would have to obtain during peak periods. In addition, the ALJ observed that if the program is successful, over time Consumers could lower future load forecasts thereby reducing future capacity costs.

Similarly, Consumers' current dynamic peak pricing (DPP) tariff limits the number of peak events to eight days per year. In this case, Consumers proposed to remove the limits on the number of days on which a peak event could be called. The Staff objected to this change, arguing that unlimited peak day events places too much risk on participants and could affect customers' willingness to participate in the DPP program. The Staff did however propose to increase the number of peak day events from 8 to 12. Consumers again argued that limiting the number of peak days could result in the disqualification of the DPP program as an LMR.

The ALJ agreed with the Staff's compromise position and recommended that the number of critical peak days in the DPP tariff be increased to 12 days per year.

Consumers filed exceptions on both recommendations to deny the company's proposed changes to the DLM and DPP tariffs. According to Consumers, the company fully supported its proposals and adopting the ALJ's recommendation would result in the loss of the benefits of the DLM and DPP programs. The Staff filed an exception in which it pointed out that the ALJ failed to address its recommendation to provide an updated credit calculation.

Consumers also proposed two changes to the rate structure of its DPP program. The first change would set the off-peak summer rate equal to the PSCR charge, and then set the mid-peak and high-peak prices using the locational marginal price. In addition, the company proposed raising the critical peak price for one of its residential DPP pilots from $0.50 to $1.00 per kilowatt-hour (kWh), while increasing the peak credit for a related pilot by the same amount.

The Staff objected to both of these changes, arguing that the use of PSCR, an average of energy-related production costs, was unnecessary and inappropriate for a non-average rate. With respect to the critical peak price change proposed by the company, the Staff recommended instead that the price be increased to $0.95 per kWh. The Staff contended that Consumers could see a similar benefit with more customer acceptance.

Consumers comments that if the Commission adopts the PFD on this issue, the claim that the lower price will increase participation will need to be validated.

The Commission finds that it is important to ensure that the DPP and DLM tariffs align with MISO requirements to qualify as LMRs. This will assure that the full capacity value can be captured by Consumers and its customers. And the Commission emphasizes that capacity is of increasing importance given the state's overall capacity outlook. *See*, *e.g.*, July 23, 2015 order in Case No. U-17751.

The Commission recognizes there may need to be some changes to existing retail tariffs to align with wholesale rules, but there also may be opportunities to shape wholesale rules to accommodate different demand response products at the retail level. Some customers may be willing to accept curtailment more often or may otherwise be more flexible, and the Commission expects that there will eventually be several tariff options available to best match the needs of different customers. The Commission agrees with the Staff's concern that the current tariff pricing was based on certain assumptions and caution is necessary in making changes to the terms and conditions without evaluating potential changes in pricing for participants; otherwise, these tariffs may not be attractive to customers. Accordingly, the Commission directs Consumers to provide updated calculations of the DLM credits in a future rate case.

Based on this record, the Commission finds that the DLM tariff should be adjusted to authorize curtailment during off-peak hours, if directed by the regional grid operator in an emergency. Such occurrences are likely to be very rare, but it does appear, based on the testimony in this case, that LMRs cannot be limited to curtailment during certain hours of the day. As for the DPP tariff, the Commission is not convinced a change from 8 to 12 events a year is necessary at this time in order to qualify as an LMR. If Consumers wishes to make changes to these programs in the future, the company will have to provide a more complete presentation on MISO's LMR requirements and on the credit calculations for participants in the DLM programs.

B. Residential Customer Charge

Consumers proposed to raise its monthly residential customer charge from $7.00 to $7.50 in accordance with its COSS. The Staff opposed this change, noting that its COSS demonstrated that the charge should be reduced to $6.40 per month. Nevertheless, the Staff took the position that rather than reducing the charge, it should remain at $7.00 per month. The ALJ agreed with the Staff, noting that, with the potentially large number of rate changes and new programs that may be offered as a result of this proceeding, retaining the current customer charge would not exacerbate customer confusion.

Consumers objected to this recommendation, arguing that the company's COSS showed an appropriate customer charge of $7.50. Notwithstanding this objection, Consumers further states, "to the extent that a different cost of service is adopted in the final rates decided by the Commission, the Company agrees that the customer charge should be adjusted accordingly, so long as the charge is not reduced below the current $7.00/month level." Consumers' exceptions, p. 62.

The Commission agrees with the ALJ's concerns about customer confusion and the need to maintain consistency with certain bill credits discussed below. The Commission therefore adopts the ALJ's recommendation and approves a residential customer charge of $7.00 per month.

C. Education Credit

MCL 460.11(9) requires that schools, universities, and colleges be charged cost-of-service-based rates. Initially, assuming a 4CP 100 production cost allocator, Consumers assigned educational institutions to their own cost class and then assigned credits or charges to bring these institutions to cost-of-service. According to Ms. Collins, however, "this approach resulted in inconsistent Power supply and Delivery charges for these customers. In some cases, Education Institution customers pay more than the other general service customers served at the same voltage and in some cases less." 5 Tr 553. Ms. Collins further explained that to address these variances, the company proposed to include educational institutions with all other general service customers served at the same voltage level, and then assign a credit to educational institution customers for the low-income assistance and senior citizen credits. In its initial brief, Consumers first raised the claim that this method was dependent on the use of a 4CP 100 production cost allocator. Consumers asserted:

> Staff's 75/0/25 production cost allocation methodology, if also approved in this case, would effectively negate the Company's above discussed Income Assistance and Senior Citizen subsidy credit which was based on the Company's initially filed determinants and costs. Thus, if the Commission adopts Staff's 75/0/25 production cost allocation methodology in this case, the Company proposes to continue the subsidy credit, as described above, and provide all Secondary and Primary Educational Institution customers a power supply credit that is consistent with the power supply credit approved for Primary Educational Institution customers in Case No. U-17688. Case No.
> U-17688, 2 TR 48.

Consumers' initial brief, p. 167.

In response, the Staff argued that "[i]t is inappropriate to modify the credit based on the results of the calculation to seek a certain result. The Company's initially proposed method in this case results in a credit to [General Educational Institution] GEI customers, regardless of allocation methodology, and therefore provides a consistent result." Staff's reply brief, p. 7.

The ALJ agreed with the Staff and recommended that the Commission adopt the company's original calculation method for the credit.

In its exceptions, Consumers reiterated:

> If the Company's cost allocation proposals in this case are not utilized by the Commission, additional modifications must be made to avoid inequitable results. These modifications are consistent with Commission's determination in Case No. U-17688 that rates should be evaluated based on the specific determinants and costs proposed or approved in a given case. . . . Thus, if the Commission adopts Staff's 75/0/25 production cost allocation methodology in this case, the Company proposes to continue the subsidy credit, as described above, and provide all Secondary and Primary Educational Institution customers a power supply credit that is consistent with the power supply credit approved for Primary Educational Institution customers in Case No. U-17688. Case No. U-17688, 2 TR 48. This approach would ensure cost-based rates for Educational Institution customers as required by 2008 Public Act 286.

Consumers' exceptions, p. 65.

In light of the fact that Consumers first raised this concern about the educational credit in its brief, and because the Staff determined that the company's initial method was reasonable and cost based, the Commission agrees with the ALJ and adopts the PFD. If Consumers or any other party wishes to revisit this issue in a subsequent rate case, it shall be addressed in testimony and exhibits on the record.

D. General Service Primary Demand Charge

The cost allocation for Rate General Service Primary Demand (GPD) was also an issue in Consumers' Act 169 proceeding. There, as here, Hemlock (and also, in this case, ABATE and

Wal-Mart) argued that the assignment of production-related capacity costs for Rate GPD should be based 100% on demand. However, the June 30 order provides:

> The Commission finds the record unclear with respect to whether the rate design advocated by Hemlock is the appropriate rate design for Rate GPD customers. As Hemlock points out, Consumers never provided information on the number or percentage of Rate GPD customers with load factors between 40% and 60%. Moreover, Hemlock's analysis appears to show that customers with load factors above 60% might see significant cost reductions. But neither Hemlock nor Consumers provided sufficient or clear information on the actual impact on low load factor customers of adopting Hemlock's proposal, including the number or percentage of customers that might be adversely affected. What is clear, however, is that the company's proposal, supported by the Staff, to change the weighting from 50% demand and 50% energy to 75% demand and 25% energy in the rate design for Rate GPD was well supported, of considerable benefit to HLF customers, and should therefore be approved.

June 30 order, p. 26.

The ALJ found that on the basis of both the record in this proceeding and the June 30 order, Consumers' proposed 70% on-peak demand and 30% energy rate design should be adopted. The ALJ agreed with the company's position that assigning cost based 100% on demand would be unreasonable given that even very high load factor customers rely "on electricity produced by generating units whenever it draws power from the utility's grid . . . it is reasonable for the company to assess that customer some charge to recover a portion of Consumers' capacity costs." PFD, p. 162.

ABATE and Hemlock take exception to the ALJ's recommendation. According to ABATE, Rate GPD costs must be allocated on a 100% demand basis to avoid intra-class subsidies, to comport with cost-causation principles, and to send accurate price signals to customers. Alternatively, ABATE argued that if the Commission decides not to adopt a 100% demand weighting at this time, it should nevertheless use a 75% demand, 25% energy weighting in final rates.

In its exceptions, Hemlock pointed out that in compliance with the June 30 order, it included more information on the percentage of customers with load factors below 40% and above 60%. According to Hemlock, only 18% of Rate GPD customers have load factors below 40%, while 70% of customers have load factors above 60%. Thus, according to Hemlock, the majority of Rate GPD customers would benefit from rates based 100% on demand and all customers would benefit from more accurate price signals.

In reply, Consumers points out that its 70% on-peak demand, 30% energy capacity cost allocation was the most reasonable for Rate GPD customers overall, and that the Staff supported the proposal. Consumers points to Exhibit A-82, which it contends demonstrates that while Hemlock's and ABATE's proposal based 100% on on-peak demand would benefit voltage level 3 customers, it would also harm voltage level 1 and voltage level 2 customers. Consumers argues that the Commission should reject the 75% demand 25% energy rate design approved in the June 30 order on grounds that the rate design in the Act 169 case was based on different costs and slightly different determinants than those used in this proceeding.

After considering the record in this proceeding, the Commission sees no reason to alter its determination that 75% of capacity costs for Rate GPD should be collected through the on-peak demand charge and the remaining 25% through energy charges. The Commission agrees it is reasonable to consider rate impacts when changing rate design. As the company demonstrated in this proceeding, demand-related costs charged based 100% on on-peak demand would not only be a significant departure from the previous 50% demand, 50% energy rate design, but it also would have a detrimental impact on voltage level 1 and voltage 2 customers. That said, the Commission reiterates:

> [T]he Commission is open to exploring in the future the development of a new class or subclass for customers that operate in such a manner that can actually lower the

> utility's cost of service due to their load profile and overall consumption. The Commission would welcome an analysis of whether and how avoided utility costs attributed to such customer characteristics and behavior could, at least in part, flow back to those customers through alternative rate designs.

June 15, 2015 order in Case No. U-17689, p. 24.

E. General Service Primary Time-Of-Use Rate Premium Time Block

Consumers proposed to increase the high-peak and mid-peak time blocks used in the company's General Service Primary Time-Of-Use (GPTU) rate. Specifically, Consumers proposed to expand the high-peak hours from two hours to three hours and expand the mid-peak hours from two hours to four hours, in both the summer and winter. According to Consumers, its changes were based on an analysis of MISO's locational marginal prices (LMPs) to determine the breaks in the highest-priced periods. The Staff agreed with the company's proposal.

Kroger indicated that while it did not disagree with the proposal in concept, it nevertheless recommended that the changes be undertaken more gradually, because Rate GPTU is a new rate that was only made available in the company's last rate case. Kroger further recommended that even if the high-peak hours are expanded, no change should be made to the mid-peak hours.

The ALJ agreed with the Staff and Consumers, highlighting the Staff's argument concerning the importance of incentivizing customers to avoid energy usage during the highest-cost periods through appropriate price signals. The ALJ therefore recommended that the Commission approve the proposed changes to Rate GPTU. There were no exceptions filed. The Commission therefore approves the recommended changes to Rate GPTU.

F. Metal Melting Pilot and Energy Intensive Primary Rate

Consumers proposed to remove the "pilot" designation from its Metal Melting Pilot (MMP) Rate and to open this rate to other energy-intensive customers, subject to certain conditions. Because the rate is expanded beyond metal melting, Consumers proposes to rename it the "Energy

Intensive Primary (EIP) Rate." Rate EIP would be limited to existing metal melting customers and 200 MW of new load not previously served by Consumers. The new load must be associated with a customer whose electric costs represent a large portion of total production costs and who has viable options to locate out of state. Finally, the incremental load must exceed 2 MW at a single site and have a load factor above 70%.

The Staff recommended that the proposed Rate EIP be approved. According to the Staff, Rate EIP, "offers customers an opportunity to shift load from peak demand periods to save on electric costs, but also subjects them to critical peak pricing events in which they pay . . . LMP prices once prices reach certain LMP thresholds if the customers do not curtail their usage. This rate prices the cost causative element appropriately and sends the proper price signal." Staff's initial brief, p. 120. The Staff also recommended approving the limitations on the rate as proposed by the company. The Staff noted that limiting the rate to 200 MW of new load will allow Consumers to evaluate Rate EIP to determine whether the rate should be expanded in the future.

ABATE and Energy Michigan supported Consumers' proposed Rate EIP, but objected to some of the conditions. ABATE pointed out that to qualify for Rate EIP, a customer must show that a significant portion of its production costs involve the purchase of electricity, and demonstrate that it has viable options for siting its facility outside of Michigan. ABATE contended that these restrictions are essentially discriminatory, thus in violation of MCL 460.557. Energy Michigan raised similar concerns, noting that in the context of electric choice, the limitations Consumers proposes would not allow a metal melting customer to move from the MMP Rate to choice and then back to Rate EIP. Energy Michigan characterizes this as unnecessarily anti-competitive.

The ALJ disagreed with ABATE and Energy Michigan, finding that "the anti-discrimination provision . . . [of MCL 460.557] does not fully restrict the Commission's broad ratemaking authority. Rather, the Commission has long been allowed to consider a variety of factors that may distinguish individual customers or entire customer classes when setting a utility's rates." PFD, p. 167. Accordingly, the ALJ found that Consumers' proposed Rate EIP, supported by the Staff, should be approved.

ABATE filed an exception, arguing that limiting Rate EIP to existing metal melting customers plus 200 MW of new load not currently served by the utility is "blatantly discriminatory," pointing out that, for example, a metal melting customer on retail choice would not be permitted to take service under Rate EIP because that customer's load would not qualify as new load, even though in all other respects this customer would be the same as other metal melting customers who are on the MMP Rate. ABATE further asserts that requiring potential customers to show that electricity was a significant amount of their total costs is vague and would unreasonably compel customers to share proprietary information with the company. ABATE contends that requiring potential customers to show that they have viable options in another state is ill-advised because these customers would have to spend time and resources determining whether there are better opportunities in other states. Finally, ABATE objects to any requirements concerning load factor, arguing that metal melting is a volatile industry and extensive shut-downs in the business are common.

In reply, Consumers points out that ABATE's objections to Rate EIP are based on conjecture and opinion and not on evidence in the record. Consumers further observes that only the company and the Staff addressed Rate EIP in testimony, thus the Commission should dismiss ABATE's exceptions as baseless.

The Commission agrees with the ALJ, the Staff, and Consumers that Rate EIP is not discriminatory and should be approved, with the limitations proposed by the company and supported by the Staff. As Consumers points out, the anti-discrimination provisions of MCL 460.557 do not supersede the Commission's broad ratemaking authority, as has been confirmed by the Court of Appeals. *Ford Motor Co v Public Service Comm*, 221 Mich App 370; 562 NW2d 224 (1997). ABATE's exception is therefore rejected.

G. Substation Ownership Credit

In calculating the joint ownership substation credit, Consumers proposed to use the previous calendar year's ratio of the customer-owned substation maximum demand to the company-owned substation maximum demand. Hemlock suggested that it would be more accurate and appropriate to apply the substation ownership credit to the maximum demand measured at substations owned by customers every month. Hemlock provided alternative language to amend Consumers' substation ownership tariff to reflect its recommendation. Consumers responded that its billing system lacks the functionality to perform the calculation in the manner suggested by Hemlock. Hemlock countered by pointing to a discovery response from Consumers that indicated that the company could program its system to perform the necessary calculation, but has not done so because, to date, it has not been required.

The ALJ agreed with Hemlock, noting that Consumers had found some merit in Hemlock's recommendation. The ALJ further found that Consumers had evinced that it already has the capability to determine the monthly demand at each substation and that it may already have the necessary functionality in its billing system that would allow the company to calculate the maximum demand at each substation. The ALJ therefore recommended that the Commission adopt the language that Hemlock proposed.

Consumers takes exception to the ALJ's recommendation, reiterating that it currently does not have the functionality to make the recommended calculation and that it would take time and significant resources to program its billing system to implement the change Hemlock proposed. Consumers adds that its proposal results in a static ratio that reflects the fact that the customer's and the company's investments in a substation do not change monthly, and, thus, the credit should not change monthly. In reply, Hemlock urges the Commission to adopt the PFD.

The Commission finds the PFD well-reasoned, and it therefore adopts the ALJ's recommendation. Although Consumers testimony and briefing indicated that it does not have the functionality to undertake the calculation of the substation ownership credit on a current basis, the company's discovery responses confirmed that the necessary functionality could fairly easily be implemented, or, as Hemlock suggested, Consumers could manually calculate the credit on the basis of the information that it apparently already collects and maintains.

H. Stand-by Rate Working Group

The Staff observed that many of Consumers' customers are interested in developing distributed generation systems, however, the company's current stand-by rates are complex and may not be appropriate for certain types of distributed generation. The Staff proposed that the Commission establish a workgroup to study various issues concerning stand-by service and rates. According to the Staff, the workgroup should provide background information on how Consumers' stand-by rates are currently developed and should explore how other states have addressed stand-by rates. Finally, the Staff suggested that the workgroup should evaluate methods that better reflect the costs and benefits of serving customers with self-service power. Consumers agreed with the Staff's proposal in concept but recommended that the Commission establish a clear agenda, that the workgroup's discussion be limited to core issues of cost of service and rate design for standby generation, and that participation in the workgroup be limited to the Staff, utilities, and current stand-by customers.

The Staff, Energy Michigan, and ABATE objected to various limitations that Consumers sought to impose on the workgroup's membership, agenda, and process. The ALJ agreed with these parties and found that the Staff's proposal should be adopted and that Consumers' proposed limitations on the workgroup membership and discussion topics should be rejected. He did, however, recommend that the Commission provide an agenda of the areas that the workgroup should address.

There were no exceptions filed. The Staff notes however, that it provided a comprehensive set of goals for the workgroup in its presentation in this case. The Commission adopts the ALJ's recommendation to establish a Stand-by Rates Workgroup, and directs the Staff to, within 90 days of the date of this order, schedule an initial meeting of the workgroup. While the Commission agrees that the goals set forth in the Staff's presentation are reasonable, the Commission nevertheless finds that the parties should be free to broaden the scope of the workgroup if necessary. Finally, the Commission directs the Staff, within nine months of the date of this order, to file a report in a new docket discussing the process and recommendations of the Stand-by Rates Workgroup.

I. Threat-of-Violence Tariff

According to Consumers, since 2010, there have been over 500 instances annually where a company employee was threatened with violence, with 16% of these occurrences involving a weapon. In response to this serious problem, the company proposed a tariff to be implemented in cases where violence against a Consumers' employee is threatened or where an act of violence occurs. Consumers explained:

> Under the proposed threats or acts of violence tariff, the Company will disconnect service of a customer who has a confirmed act or threat of violence against a Company employee or contractor. 6 Tr 808. Depending on the circumstances, different threat codes are assigned to the customer's account to ensure awareness of Company representatives in the service territory. 6 Tr 809. On threat coded accounts, the Company will perform a semiannual review, or review the account at the request of the customer, and service will remain shut off until it is clear that the threat has been resolved. 6 Tr 815. Additionally, the Company would have the ability to collect reasonable costs associated with the threat or act of violence from the customer prior to restoring service. 6 Tr 810.

Consumers' initial brief, p. 171.

The Staff and the RCG opposed this proposal. The Staff argued that the implementation of the proposed tariff could in fact escalate an already volatile situation, resulting in a greater likelihood that violence may occur. The Staff also objects to the company's ability to collect what the company deems "reasonable costs" resulting from a threat or act of violence, including medical costs, costs of investigation and prosecution, property damage, and costs of additional security for employees. The Staff contends that the determination and assessment of costs is for the courts to decide and the proposed tariff provides the company with far too much discretion. In sum, the Staff maintains that the Threat-of-Violence Tariff is designed to be punitive and:

> [it] demonstrates the Company's attempt to assert power that is properly the domain of the legal system. These tariff changes would allow the Company to determine the existence of a threat (as the Company perceives it), punish the customer by disconnecting service and assessing charges, and give the Company the ability to unilaterally decide damages, and decide when, or if, service is restored. These powers are outside the scope of a regulated energy utility and, therefore, the ALJ and the Commission should reject them.

Staff's initial brief, p. 134.

The RCG likewise opposed the tariff on grounds that it would allow the company to immediately cut off service without notice or a hearing. The RCG also raised concerns about the vagueness of what constitutes a threat or who decides whether a threat has been made.

The ALJ agreed with the Staff and the RCG, finding that "the utility's proposed response to threats or acts of violence is poorly defined, potentially counter-productive, and borderline excessive." PFD, p. 174. The ALJ agreed that the tariff was impermissibly vague about the type of threat that would rise to the level where the tariff provisions would be implemented, and it was unclear about how or when law enforcement or the courts would be involved. The ALJ further determined that it was uncertain what the "reasonable costs" are that can be recovered from a customer. Finally, the ALJ found that the tariff would diverge from the normal requirement that a utility provide notice to a customer prior to disconnection.

Consumers takes exception to the ALJ's recommendation, arguing that the Threat-of-Violence Tariff is a reasonable means to address threats or acts of violence. Consumers contends that the ALJ's reasoning was flawed in finding that the tariff did not precisely explain the company's costs, noting that the costs at issue are "reasonable incremental costs that are directly associated with the customer's threat or act of violence. . . [including] the Company's investigation of the threat, the operating crews required to terminate service, and any other directly-related expenses incurred by the Company due to an injury as a result of a physical assault or related threat." Consumers' exceptions, p. 69. Consumers further argues that in most cases, customers are being disconnected as a result of non-payment or theft and have therefore already received notice of the disconnection. Finally, Consumers claims that although the tariff does not specify third-party involvement, this does not mean that law enforcement or the courts will not be engaged in the process. Nevertheless, Consumers points out that the company is powerless to contact the police because only the employee who was threatened or injured can file a police report.

The RCG replies, urging the Commission to adopt the PFD and reject the Threat-of-Violence tariff. The RCG reiterates that the proposed tariff provides the company with unfettered discretion with respect to determining when the provisions of the tariff should be implemented, whether or not third-parties should be involved, what constitutes "reasonable" costs, and when a customer has sufficiently complied so that he or she might be reconnected.

The Commission finds the PFD well-reasoned and adopts its findings and conclusions. The Commission agrees with all of the parties that weighed in on this issue that the safety of Consumers' employees is of paramount concern. However, the company's proposed tariff does not appear to be an appropriate means to address this concern. The Commission agrees with the Staff that disconnection of service is quite likely to escalate an already fraught situation. And the Commission further observes that in the face of an act of violence, or the threat thereof, Consumers' employees should be <u>required</u> to contact law enforcement before proceeding with disconnection or with any work to be done to utility equipment on the customer's premises. Finally, the Commission finds that Consumers may avail itself of the civil court system for redress for personal injuries or damages it might suffer in the event of a violent encounter.

J. Advanced Metering Infrastructure Opt-Out Tariff

Consumers explained that its current AMI program reasonably provides customers with the choice of opting out of AMI meter installation and that its opt-out tariff is cost-of-service based. The company claimed that, because only a small number of customers want to opt out and because opting out provides no general benefits to all of Consumers' customers, it is appropriate for those customers opting out to assume the costs of developing systems and business processes necessary to support that option. The company explained that the Commission approved its existing opt-out tariff in the June 28, 2013 order in Case No. U- 17087 (June 28 order). Opt-out customers are currently required to pay an initial upfront cost of either $69.39 or $123.91 to either retain existing legacy meters or to replace a previously-installed smart meter with a legacy meter. Opt-out customers also pay a monthly fee of $9.72 to cover the costs of reading and testing the legacy meters as well as the costs for the billing system necessary to support the older meters.

In the rebuttal portion of the proceeding, Consumers presented evidence that its initial estimate of the costs of opting out was substantially lower than the actual costs of opting out, in part because the number of customers who actually chose to opt out was smaller than that originally predicted. Consumers requested an increase in the opt-out surcharges and also requested that the Commission remove the exclusion in the opt-out tariff for apartment complexes and other dwellings with meter banks serving multiple customers.

The RCG opposed the continuation of the opt-out fees, arguing that these charges are unjust, unreasonable, and unnecessary. The RCG claimed that the primary purpose of the fees was to penalize those who opted out or to discourage customers from asserting their rights to refuse consent to the intrusive data collection technology at their homes.

The RCG also argued that the AMI program violates customers' rights under the Fourth and Fourteenth Amendments of the U.S. Constitution, as well as, Article 1, §11 of the Michigan Constitution. It claimed that the AMI program authorized by the Commission constitutes government action, as opposed to private action, and argued that the Commission's orders that establish AMI tariffs and provide cost recovery for the program invade a customer's reasonable expectation of privacy. The RCG asserted that the Commission could have approved a lawful program by allowing customers to opt-in, instead of opt-out, and by avoiding the punitive charges applied to customers who refuse to give their consent to the installation of the new meters. The RCG argued that the opt-out tariff is also unconstitutional as applied to customers who receive smart meters without their knowledge and consent.

The RCG argued that an opt-in AMI program would address customers' concerns about privacy, health, and safety because it would require advance notice and consent. The RCG further noted that the Commission approved the opt-out tariff in an informal proceeding, as opposed to a contested case proceeding or formal rulemaking, and failed to consider the legal and constitutional implications of its action. Thus, the RCG claimed that the Commission unlawfully adopted the opt-out tariff and that the ALJ could remedy this error by adopting an opt-in tariff.

The Staff argued that an opt-in tariff would be inappropriate because it is impractical, inconsistent with how utility infrastructure upgrades are traditionally handled, and contrary to the Commission's September 11, 2012 order in Case U-17000. The Staff argued that an opt-in tariff is unrealistic, because meters are not optional equipment that the customer may choose. Instead, metering equipment is owned by the utility as a part of its infrastructure. Accordingly, the Staff recommended that the Commission reject the RCG's proposal.

The Staff opposed Consumers' proposed increase in AMI opt-out charges. The Staff observed that Consumers waited until rebuttal to present its updated calculation and that this delay made it difficult to review the substantial changes proposed. The Staff recognized that the utility experienced a smaller percentage of customers opting out than it anticipated, but nevertheless argued that this trend could change as Consumers completes its AMI roll out.

The Staff disagreed with the RCG's argument that opt-out customers were subsidizing the AMI program, pointing out that the Staff included a credit for AMI costs when it calculated the opt-out fee. Likewise, the Staff disagreed with RCG's claim that the charges were not based on cost-causation, arguing that opt-out customers are causing costs that would not be necessary but for their opting out.

The Staff also disagreed with the RCG that the fact that the opt-out charges provide the utility with a small amount of revenue, compared to total revenue, justifies the discontinuance of the opt-out charges. The Staff explained that, if opt-out customers did not pay the costs they cause, other customers would have to subsidize opt-out customers. With regard to continuation of the existing opt-out tariff, the Staff argued that an AMI-specific COSS is unnecessary because the amount of AMI costs included in rates is a known quantity, subject to removal from the opt-out charge.

The ALJ noted that no party objected to Consumers' proposal to expand the availability of its existing non-transmitting meter tariff to multi-unit dwellings and thus recommended its approval. The ALJ further recommended rejecting Consumers' updated charges on grounds that the current opt-out charges are new and the updated charges were presented too late in the case to provide for meaningful review.

The ALJ recommended that the Commission reject the RCG's AMI opt-in proposal on grounds that the proposal ignored the fact that the choice of meter is a matter of management prerogative. Second, adopting the RCG's proposal would force other ratepayers to bear the cost of meter reading for non-transmitting meters, as well as the cost to maintain and test those meters. Third, the ALJ found that the requisite governmental action necessary to successfully assert a constitutional challenge was missing. Accordingly, the ALJ recommended that the Commission adopt the utility's unopposed proposal to expand the coverage of its non-transmitting meter tariff to multi-unit dwellings, and further recommended that the Commission reject all other requests to alter the existing AMI-related tariff language.

The RCG takes exception to the ALJ's rejection of its proposal to create an opt-in AMI program, arguing that the PFD lacked evidentiary support and factual and legal analyses to support its conclusions. First, RCG disagrees with the PFD's finding that the choice of metering technology is a management prerogative. According to the RCG, this statement diminishes the Commission's regulatory authority and its discretion to adopt and authorize tariffs and mandates that are reasonable and lawful. The RCG further suggests the opt-out approach does not reflect a proper balancing of utility stockholder and ratepayer interests, contrary to the Commission's duty. *City of Detroit v PSC*, 308 Mich 706; 14 NW2d 784 (1944). The RCG also considers irrelevant the fact that only a small percentage of customers have opted out, and it disagrees with the conclusion that the opt-in proposal forces other ratepayers to subsidize customers who opt out, claiming there is no record evidence supporting this statement.

The RCG takes exception to the ALJ's conclusion that no state action has occurred and therefore a constitutional challenge to the AMI opt-out program cannot be sustained. According to the RCG, the Commission's tariff approval constitutes direct state action by the Commission as a governmental agency because no AMI program could be implemented without prior Commission approval of the governing tariffs and the revenue requirements to support AMI deployment. The RCG reasserts that the Commission-approved opt-out charges are punitive rather than cost-based. The RCG argues that customers have no choice but to accept a smart meter or pay, and that, once the meter is installed, no customer's data is secure.

The RCG further claims that the Commission's orders providing for the AMI program invade a customer's "reasonable expectation of privacy," thus establishing a violation of the Fourth Amendment. The RCG further asserts that it is erroneous to assume that customers are not harmed by AMI data collection, unless that data is seized by the government. The RCG claims that customer data is not secure once collected and can be easily transferred by the utility, a third party, or a hacker. In a related exception, the RCG argues that the Commission does not have authority to waive the constitutional rights of individual citizens nor is it empowered to decide constitutional questions that are matters for the courts.

The RCG argues that there is no express authority for the Commission to impose a surcharge on customers who opt out of an AMI program, and points out that the Michigan Court of Appeals has reversed the Commission's imposition of costs and fees in the past. The RCG highlights the remand of the Commission's decision to approve the opt-out tariff in Case No. U-17087. According to the RCG, a statute should specifically authorize the Commission to adopt an opt-out tariff.

The RCG further takes exception to the recommendation in the PFD that the current opt-out fees should be continued. Instead, the RCG argues that the Commission should adopt zero initial and monthly opt-out fees because no COSS was presented either by the utility or the Staff to support the fees. According to the RCG, the Commission's rulings in Case Nos. U-17053, U-17087, and U-17000 require that opt-out fees be reviewed in each case. According to the RCG, under cross examination, both Consumers' and the Staff's witnesses acknowledged that they had not conducted a COSS to support the opt-out fees.

The RCG further asserts that Consumers' justification for the monthly opt-out surcharges is based on the theory that the company would have to undertake monthly meter reads. According to the RCG, this assumption ignores the fact that, at times, Consumers estimates usage and that the Commission's billing rules permit customers to self-read and report their monthly usage, provided that estimated reads are verified by a utility meter read once a year.

The RCG also disagrees with the suggestion by Consumers, the Staff, and the PFD, that opt-out charges are necessary to prevent opt-out customers from being subsidized by other customers. The RCG explains that opt-out customers save Consumers the cost of a meter, the cost of labor to install the meter, and also save customers the cost of scrapping perfectly reliable analog meters, with associated charges in rates in the form of net plant balances or depreciation (or both). The RCG further suggests that it is counterintuitive to accept the company's argument that fewer opt-out customers justifies higher opt-out fees. Rather, the RCG suggests that, fewer opt-out customers should result in lower costs.

The RCG argues that the opt-out customers are paying the same as all other ratepayers for AMI, even though they do not have smart meters and do not require Consumers to incur costs to install smart meters on their premises. According to the RCG, there has been no showing whatsoever that the opt-out customers are being properly credited for the cost savings they generate by not having a smart meter installed, such as avoiding the cost of the meter, installation, related property taxes, depreciation, and other costs. The RCG claims that no one in this case presented any support to demonstrate what constitutes the proper updated credit to be provided to opt-out customers. In summary, the RCG argues that, in the absence of any analysis of evidentiary support for the opt-out fees and in light of the Commission's holding that opt-out fees would be reviewed and determined based on cost principles in rate cases, the RCG argues that the Commission should adopt zero opt-out fees. Further, the RCG suggests the surcharges are not worth the trouble and do not warrant the extra billing and accounting expense.

Last, the RCG takes exception to the PFD's failure to address tariff provisions or utility practices where Consumers terminates or threatens to terminate electric service to customers who refuse a smart meter, calling the immediate cutoff of service a draconian and unnecessary action inconsistent with the Commission's rules prohibiting the shut off of electric service to senior citizens during winter months.

Consumers replies that the Commission should reject the RCG's proposal to adopt an opt-in approach to AMI metering. The company argues the Commission has the authority to determine cost recovery for the metering equipment that the utility chooses to implement. Consumers asserts that changing to an opt-in approach would complicate and delay the AMI program's implementation and would significantly increase the program's costs without any increase in commensurate benefits.

Consumers disagrees that the Commission lacks the authority to approve an AMI opt-out program, and argues that the Commission's ratemaking authority includes the authority to impose charges and expenses based on a utility's costs of operation. Consumers also rejects the RCG's argument that the company's opt-out fees are not supported with cost information. It explains that existing charges are based on the cost information presented in Case No. U-17087. Further, Consumers cites testimony explaining that the company's non-transmitting meter charges were not made a part of the base rate request in Case No. U-17087.

The company contends that the RCG's arguments regarding annual, as opposed to monthly, meter reads as a cost reduction method are "inconsistent with standard utility practice and the need for accurate meter readings." Consumers' Replies, p. 71. Consumers argues that the Commission's rules expressly require actual meter reads, and further argues that customers who choose to opt-out should not be allowed to avoid actual meter reads that are consistent with Consumers' established practice as dictated by the Commission's rules. Consumers argues that RCG's vague speculation that customers could perform meter reads is not a reasonable basis for the company to reduce its meter reading workforce which remains necessary in order to accommodate the customers who choose to have a non-transmitting meter.

Consumers also argues against eliminating the opt-out fees altogether. Consumers contends that it would be unfair and unreasonable to allocate the costs of the non-transmitting meter option to the company or to customers who do not choose that option. The utility further urges the Commission to reject RCG's contention that non-transmitting meter fees are a "penalty charge" arguing that this assertion has no factual basis. According to Consumers, the costs are not penalty fees but are cost-based charges designed to cover the opt-out costs that opt-out customers incur. The utility further contends that the Commission-approved credit included in the opt-out charges approved in Case No. U-17087 removes the costs included in base rates for AMI infrastructure and meter reading.

Regarding the RCG's constitutional challenges to the utility's existing opt-out program, Consumers argues that the Commission should reject these arguments because the RCG fails to allege factual circumstances that suggest a governmental entity has violated the Fourth Amendment prohibition against unreasonable searches and seizures as part of the utility's AMI program. The company explains that it is a private utility that has chosen to exercise its management prerogative to install AMI meters to replace older outdated non-communicating analog and digital meters throughout its service territory. The company explains that it is the entity implementing this program and not the Commission. Further, it asserts that it is requesting that the Commission approve opt-out rates to recover the costs to serve customers who choose to opt-out of having their electricity metered by an AMI meter. According to Consumers, these facts do not establish a search and seizure by a government actor, which it argues is a key component of any Fourth Amendment claim.

Consumers further argues that its implementation strategy for the AMI program is a reasonable one that provides customers with ample notification of the installation of smart meters at their premises and informs customers of their ability to opt out of a smart meter. Regarding consent, Consumers argues that utility customers consent to receiving a meter when they request utility service from the company.

Consumers also argues that the RCG's claims of immediate shutoff of electric service to customers who choose to opt out is not supported by any record evidence or tariff provision. Rather, a customer who opts out is provided with a Commission-approved alternative. Further, Consumers argues that in the event that shut off is required for another reason, the company complies with the Commission's rules and procedures that govern the shutoff of electric utility service. Thus, Consumers urges the Commission to reject these claims.

The Commission concludes that the ALJ's finding that approval of the AMI program and related tariffs does not constitute state action was correct. In *Detroit Edison v Stenman*, ___ Mich App ___; ___ NW2d ___ (2015) (Docket No. 32103), the Court of Appeals considered this very issue and concluded that the defendant homeowners failed to show, or even argue, that an illegal search was performed through the smart meter that was installed on their property. *Id*., slip op. at 11. The Court further concluded that the defendant homeowners failed to establish that the utility's installation of smart meters constitutes governmental action for Fourth Amendment purposes. Significantly, the Court opined, "Even if the state and federal governments have advocated or incentivized, as a matter of public policy, the use of smart meters, there is no indication that the government controls the operations of plaintiff, an investor-owned utility, or that plaintiff acts as an agent of the state or federal governments." *Id*.

Likewise, the Supreme Court of the United States has determined that a public utility commission's approval of a tariff is not state action. *Jackson v Metro Edison Co*, 419 US 345, 357; 95 S Ct 449; 42 L Ed 2d 477 (1974). In *Jackson*, the United States Supreme Court stated:

> The nature of governmental regulation of private utilities is such that a utility may frequently be required by the state regulatory scheme to obtain approval for practices a business regulated in less detail would be free to institute without any approval from a regulatory body. Approval by a state utility commission of such a request from a regulated utility, where the commission has not put its own weight on the side of the proposed practice by ordering it, does not transmute a practice initiated by the utility and approved by the commission into 'state action.' At most the Commission's failure to overturn this practice amounts to no more than a determination that a Pennsylvania utility was authorized to employ such a practice if it so desired. Respondents' exercise of the choice allowed by state law where the initiative comes from it and not from the State [footnote omitted], does not make its action in doing so 'state action' for purposes of the Fourteenth Amendment.

In *Blum v Yaretsky*, 457 US 991, 1004; 102 S Ct 2777; 73 L Ed 2d 534 (1982), the Supreme Court explained that the purpose of the "state action" analysis in *Jackson* is to ensure that constitutional safeguards are only invoked when it can be said that the state can be held "responsible" for the specific conduct complained about. Here, the Commission views that specific conduct to be the installation of AMI meters on the homes and businesses of customers and any alleged privacy violations that could arise from the use of those meters. The Court further opined that, "a State normally can be held responsible for a private decision only when it has exercised coercive power or has provided such significant encouragement, either overt or covert, that the choice must in law be deemed to be that of the State. * * * Mere approval of or acquiescence in the initiatives of a private party is not sufficient to justify holding the state responsible for those initiatives under the Fourteenth Amendment." *Id*., 457 US at 1004-1005.

The flaw in the RCG's Fourth Amendment argument is its continued insistence that Commission approval of the AMI program and related opt-out tariff is the same as a Commission mandate. However, the Commission did not order Consumers to purchase AMI meters or install them on the homes and businesses of its customers. Consumers' decision to implement AMI was a decision that the Commission took no part in.

Further, the cases that RCG relies on are distinguishable from the opt-out tariff here because those cases clearly involved government action, either by a municipal utility or the police. Morever, because there is no state action implicated in the approval of AMI costs and tariffs, the RCG's related claim that the Commission lacks jurisdiction to waive customers' constitutional rights is also rejected.

The RCG next contends that there is no federal or state law that authorizes the Commission to impose a surcharge on customers who opt out of an AMI program. This argument lacks merit. MCL 460.6(1) sets forth the powers and jurisdiction of the Commission, and the Commission's authority to approve an opt-out charge is derived from its general ratemaking authority identified in this statute. This conclusion is consistent with any number of judicial opinions. *See, e.g., Attorney General v Pub Serv Comm*, unpublished per curiam opinion of the Court of Appeals, issued April 30, 2015 (Docket No. 317456), page 5 (where the Court opined that a decision to approve opt-out tariff rates and to impose charges and expenses based on a utility's costs of operation is within the Commission's ratemaking authority). Accordingly, the Commission rejects this argument as baseless.

The RCG further asserts that Michigan law does not mandate an AMI meter for opt-out customers. This claim is correct but inconsequential. Michigan law does not mandate the specific use of particular equipment by any utility. *See*, *In re Application of Detroit Edison Co to Implement Opt Out Program*, unpublished per curiam opinion of the Court of Appeals, issued February 19, 2015 (Docket Nos. 316728 and 316781), p. 5. And, the Commission may not tell a utility how to run its company or what equipment to purchase. *Union Carbide Corp v Pub Serv Comm'n*, 431 Mich 135, 148; 428 NW2d 322 (1988). However, the Commission need not allow a utility to recoup in its rates expenses that are neither reasonable nor prudent.

The RCG also criticizes the Commission's order in Case No. U-17087 arguing that the opt-out fee approved in that case was not supported by the record and resulted in no individual benefit for the customer choosing to opt-out. The Commission's order in U-17087 may not be collaterally attacked in this case. *Kosch v Kosch*, 233 Mich App 346, 353; 592 NW2d 434 (1999); *In re Application of Detroit Edison Co to Implement Opt Out Program*, *supra*, p. 6. The order the RCG references in Case No. U-17087 was appealed and litigation is still ongoing in that case. Regardless of the outcome of that litigation, the issues in this docket apply to a time period that is separate and distinct from the time period the order in Case No. U-17087 governs. Accordingly, this is not the correct forum for the RCG to question the evidentiary support for the Commission's order issued in a separate docket.

Because Consumers and the Staff both rely on the cost of service information presented in Case No. U-17087 as support for the continuation of the current opt-out fees and charges the Commission approved in that case, it is useful for the Commission to briefly discuss case law regarding relitigation of issues and claims addressed in a different Commission docket. In *Pennwalt v Pub Serv Comm'n*, 166 Mich App 1; 420 NW2d 156 (1988), the Court of Appeals held that, because ratemaking is a legislative function rather than a judicial one, the legal doctrines of res judicata and collateral estoppel do not apply in a strict sense. However, the Court went on to conclude that, in order to balance the competing interests of administrative economy while giving the plaintiff the chance to challenge a rate increase, the burden shifts to the plaintiff to establish by new evidence or a change in circumstances a reason that the issue or claim must be relitigated. *Id.*, p. 9.

Here, applying the burden-shifting analysis the Court articulated in *Pennwalt*, it is the RCG's responsibility to come forward with new evidence or evidence of a change in circumstances that would lead the Commission to conclude that the existing opt-out fees are not reasonable and prudent. The RCG provides a two-fold argument for why the currently existing monthly opt-out charges and initial opt-out fees are not cost-based. First, the RCG argues that some of the initial fees charged to opt out improperly include the cost to eventually replace a meter with a smart meter. Second, the RCG argues that the monthly meter reading charges are unnecessary because the utility can estimate meter readings and opt-out customers can self-report their meter reads via a mail-in postcard. As will be discussed further below, these arguments fail to present new evidence or evidence of a change of circumstances rendering the existing opt-out fee structure unreasonable. Accordingly, the Commission concludes that, because the RCG has failed to sustain its burden of producing evidence that would warrant a thorough re-examination of the issues presented in Case No. U-17087, and because the RCG may not collaterally attack the Commission's determinations in a different case, the Commission's reliance on its approval of the existing opt-out fees in Case No. U-17087 is appropriate.

In a similar argument, the RCG contends that the existing opt-out fees and charges should be reduced to zero in part because no Consumers or Staff witness introduced a formal COSS in this proceeding to support the continuation of existing opt-out fees and charges. The Commission disagrees. Although the RCG argued that the Commission's order in Case No. U-17087 requires charges associated with opting-out to be reviewed in "each and every future rate case," Mr. Warriner explained that this is untrue. 6 Tr 961. Rather, the Commission's statement related to its approval of continued full deployment of AMI, and not opt-out charges. *Id*. Costs associated with full AMI deployment and opt-out charges are not the same and should not be confused. Because cost support for those opt-out fees and charges was provided in Case No. U-17087, the Commission may rely on its determinations in that case. Regardless, Mr. Warriner did testify to some extent about the costs involved that warrant the opt-out fees and charges. He explained that the charges were developed to recover the costs associated with developing and maintaining a non-transmitting meter option. *Id*. Mr. Warriner summarized the work required to implement a smart meter opt-out option and identified the associated cost of systems development for this option to be $1,072,600. 6 Tr 962-963. He explained that even with lower opt-out participation rates than what the company originally projected, Consumers is projecting the need for 21 meter readers for opt-out meter reading. He recommended retaining the fees due to the obvious costs associated with the opt-out program. *Id*., p. 964.

The Commission disagrees with the RCG's argument that the opt-out fees and charges are not cost-based and relies on the evidentiary record and its approval of those fees and charges in Case No. U-17087. The Commission further agrees with Consumers that estimated reads and self-meter reading are not established utility practice and are not the preferred method of meter reading that the Commission requires in its rules. Estimated reads and instances where a customer reads their own meter and sends the reading to the utility via a postcard are the exception rather than the norm. The fact that other methods of reading a meter exist does not persuade the Commission that the opt-out fees and charges it approved in Case No. U-17087 are not cost-based. The RCG has supplied no contradictory evidence detailing how many opt-out customers are bypassing monthly meter reads. There is no evidentiary basis to alter the status quo by reducing or eliminating the opt-out fees and charges that the Commission approved in Case No. U-17087. Accordingly, the Commission finds reasonable and adopts the PFD's recommendation to continue the opt-out fees and charges it approved in Case No. U-17087.

Regarding the RCG's arguments that the initial and monthly surcharges are a penalty or that the surcharge is duplicative, the Commission disagrees and rejects these arguments. The testimony of Mr. Warriner establishes that the opt-out surcharges at issue in this case are not a penalty but are cost-based. Consumers provides customers who do not want a smart meter with a legacy (non-communicating) meter. 6 Tr 939. Mr. Warriner explained that charges associated with the manual meter reading program were authorized in Case No. U-17087, and those charges cover the costs to maintain and test the legacy equipment and to obtain monthly manual meter readings. Mr. Warriner further testified that opt-out customers were first charged those fees in April 2014. As of November 2, 2014, 0.46% of customers in areas where AMI meters have been installed chose the manual meter reading service option. *Id*. Mr. Warriner also testified that the opt-out tariff is designed to recover incremental costs caused by customers' decisions to opt out of the standard AMI metering technology.

Mr. Warriner disagreed that the non-transmitting meter charges approved in Case No. U-17087 are a penalty that forces customers to accept the installation of a smart meter, explaining that the charges were developed to recover the costs associated with implementing and maintaining a non-transmitting meter option. 6 Tr 961. Mr. Warriner also explained the costs Consumers incurred to provide an opt-out option. He testified that 5,306 hours of work by a mix of employees and contractors with IT development and testing skills was required to offer this option. He further explained that hourly rates for these types of technical resources range from $66 per hour to $320 per hour, and that an average rate of $200 per hour was used to calculate the $1,072,600 cost of systems associated with the smart meter deployment exceptions process. 6 Tr 962-963.

Testimony was also presented that discredited the RCG's argument that the opt-out charges were duplicative. Nicholas Revere, Manager of the Rates and Tariffs Section of the Commission's Regulated Energy Division, testified that this claim was "demonstrably false." 9 Tr 1868. Mr.

Revere indicated that the opt-out charges the Commission approved in Case No. U-17087 included adjustments proposed by the Staff that removed AMI costs, as shown on page 4 of Exhibit S-6, Schedule F5 in the same case. *Id*. Based on the testimony reviewed above, the Commission rejects the arguments that the challenged opt-out charges are penalties or duplicate charges.

Regarding the RCG's argument that the company is installing smart meters without first notifying customers or obtaining their advance consent, the Commission concludes that the record evidence adequately disproves these claims. Mr. Warriner testified at length about the notification process that accompanies the utility's smart meter installation:

> The customer notification process begins with public outreach and advertisements in planned implementation areas at least six months prior to meters being scheduled for installation. Public outreach efforts include presentations to municipal and community organizations about the Smart Energy Program installation schedule and process. In addition, billboards and digital media provide another source of general awareness to customers. Individual customers are mailed postcard notifications 30 days prior to the scheduled meter upgrade. The Company also mails individual letters to customers 14 days prior to their scheduled meter upgrade, detailing what to expect on the day of the upgrade and what to do if they have questions. Lastly, the Saturday before the week of the scheduled upgrade, an automated call is made to the customer, again notifying them of the scheduled upgrade and providing a toll free phone number for questions or to schedule an appointment, if desired. [6 Tr 957-958.]

The Commission notes that no evidence was presented to refute this testimony about Consumers' notification procedure in this case. Accordingly, the Commission finds the RCG's claim that customers are not notified in advance of a smart meter installation must be rejected.

Likewise, the Commission rejects the RCG's argument that Consumers is installing AMI metering technology without first obtaining the express consent of its customers. There was testimony that Consumers considers smart meters to be standard metering technology, and that by agreeing to take electric service, the customer provides consent to having a meter. 6 Tr 959. The

Commission therefore finds that Consumers is not installing standard metering technology without the express consent of the customers it serves.

Regarding the RCG's argument that long-standing judicial precedent provides that the Commission may only issue binding orders in contested cases, or in formal rulemaking proceedings in accordance with the Michigan Administrative Procedures Act, MCL 24.206 *et al.*, the Commission simply notes that the Court of Appeals ruled otherwise when it held that the Commission could rely on its previous determinations in Case No. U-17000. *See, In re Application of Detroit Edison Company To Implement Opt Out Program,* unpublished per curiam opinion of the Court of Appeals, issued February 19, 2015 (Docket Nos. 316728 and 316781). Accordingly, the Commission rejects this argument.

The RCG urges the Commission to require Consumers to adopt an opt-in approach where customers could request the installation of a smart meter instead of opting out of smart meter installation. The Commission agrees with the ALJ's reasoning articulated in the PFD and rejects this proposal. First, a Commission directive telling Consumers to adopt an opt-in approach is tantamount to the Commission telling the company what metering technology to use. But, Michigan courts have concluded that a utility's decision about what metering equipment to use is a management decision outside of the Commission's authority. *In re Application of Detroit Edison Co to Implement Opt Out Program*, *supra*, p. 5. Moreover, the RCG's suggestion is not practical in part because of the fact that the installation of AMI meters in Consumers' service territory is well underway and is scheduled to be completed in 2017. A change in approach at this time, even were it within the Commission's scope of authority, would come at substantial ratepayer cost. Moreover, the Commission finds persuasive the Staff's evidence that an opt-in approach does not reflect the reality of utility service today, in that meters are not optional equipment but rather essential to utility service. 10 Tr 2095-2096. The Commission finds the PFD's findings and conclusions well-reasoned and adopts the PFD's recommendation that it reject this proposal.

Last, the RCG argues that the company engages in the draconian practice of immediately terminating electric service when a customer elects to opt out of smart meter installation. There is no evidentiary support for this argument in the record. Rather, the record indicates that customers who elect to opt out of smart meter installation are provided with a non-transmitting legacy meter. Accordingly, the Commission rejects this argument.

X. OTHER ISSUES

A. Appeals of Evidentiary Rulings

On April 4, 2015, pursuant to MCR 2.302(C)(8), and Mich Admin Code, R 792.10432, Consumers filed a motion for an order protecting certain confidential or commercially sensitive information (confidential information) that was previously provided to the Staff, the Attorney General, and MEC/NRDC under a confidentiality agreement. The confidentiality agreement stipulated that if any of the signatories to the agreement sought to introduce confidential information into the record in this proceeding, it could only do so under a protective order. Subsequently, MEC/NRDC requested to include some of the confidential information in its presentation in this case. In its proposed protective order, Consumers included language that required that any confidential information obtained from the company in this proceeding be returned to Consumers or destroyed at the end of the case.

In response to Consumers' motion and proposed protective order, MEC/NRDC requested that a provision be added to the protective order that would allow MEC/NRDC to retain one copy of the confidential information for possible use in future proceedings, subject to protective orders entered in those proceedings. Specifically, MEC/NRDC requested that the following paragraph be added to the protective order:

> Counsel for the requesting Party or Parties may maintain a single confidential file of Protected Material subject to all other provisions in this Order. If the Protected Material is relevant or reasonably calculated to lead to admissible evidence in a future Commission case, then it may be used subject to the issuing of a new protective order in that case. Counsel for the requesting Party or Parties shall have the right to retain copies of the pleadings, orders, transcripts, briefs, comments, and exhibits in these proceedings, but this Order will continue in effect with respect to the Protected Material contained in these documents.

MEC/NRDC's response to Consumers' motion for a protective order, p. 2.

MEC/NRDC noted that the language it proposed was identical to the language used in a protective order issued in DTE Electric Company's (DTE Electric) pending rate case and substantially similar to language contained in protective orders issued in DTE Electric's two most recent PSCR proceedings. MEC/NRDC argued that the information covered by the protective order originated in previous Consumers' proceedings, thus demonstrating that information obtained in one proceeding may have relevance in a future proceeding.

At a hearing on May 5, 2015, the ALJ granted the request for a protective order and ruled that counsel for MEC/NRDC should be allowed to retain a copy the confidential information until the conclusion of Consumers' next general electric rate case or the conclusion of any PSCR plan or reconciliation proceedings which are filed before the conclusion of the company's next general electric rate case, whichever occurs later. On May 11, 2015, MEC/NRDC filed a proposed protective order. On May 18, 2015, Consumers filed objections to certain language in that order that it claimed expanded the scope of the ALJ's ruling. Consumers also reserved its right to appeal the ALJ's determination that confidential information could be maintained by a party after the close of this proceeding. On June 11, 2015, the ALJ issued a protective order that included language substantially similar to that requested by MEC/NRDC.

In its exceptions, Consumers appeals the ALJ's ruling allowing the retention of confidential information for use in future proceedings. Consumers argues that the language approved by the ALJ in the protective order violates the terms of the confidentiality agreement entered into by MEC/NRDC and other parties. Consumers contends that Paragraph 5 of the agreement provides:

> This Agreement shall be effective when signed and shall remain in effect until the issuance of a final order in . . . Case No. U-17735 at which time the Confidential Information in the possession of [signing party] shall be returned to Consumers Energy. The obligations of the parties under this Agreement will survive termination of this Agreement and will remain binding on the parties for a period of two (2) years from the last date of disclosure under this Agreement.

Consumers therefore argues that the language in the protective order allowing parties to retain confidential information after the issuance of the final order in this case is contrary to the terms of the confidentiality agreement that the parties, including MEC/NRDC, made when they entered into the agreement.

In response, MEC/NRDC argue that the ALJ's decision to grant the protective order, with a provision allowing the retention of confidential information for a limited time and for limited purposes should be reviewed for an abuse of discretion. Under that standard, Consumers' appeal should be rejected. With respect to the confidentiality agreement, MEC/NRDC argue that this is a separate agreement applicable to some of the parties to this proceeding and that it is not relevant to the issue on appeal.

As MEC/NRDC point out, protective orders, like most pretrial matters, are reviewed for an abuse of discretion. *Briggs v Upjohn Co*, 200 Mich App 62, 65; 503 NW2d 695; January 20, 1982 order in Case No. U-6923; and November 29, 1993 order in Case No. U-10335. The Commission further notes that several protective orders have been recently issued that allow parties to retain confidential information from one proceeding for possible use in a subsequent proceeding. In this case, the ALJ crafted a narrower order that only allows the information to be retained for a limited time period. Because the protective order tracks the language in other protective orders, and because the use of any confidential information obtained in this proceeding would require another protective order if used in another proceeding, the Commission does not find an abuse of discretion in the ALJ's ruling. The Commission therefore finds that Consumers' appeal should be denied.

In a similar vein, the RCG appeals the ALJ's ruling on a motion in limine, as well as various rulings on objections in the evidentiary hearings, on grounds that these rulings limited evidence that could be introduced concerning the health, safety, and privacy implications of AMI. The RCG reiterates that the Commission cannot rely on its orders in Case Nos. U-17000 and U-17102 because there was no underlying contested case proceeding.

The Commission again notes that appeals of evidentiary matters should be reviewed for an abuse of discretion, and that in *In re Application of Detroit Edison Company to Implement Opt-Out Program*, *supra*, the Court rejected a similar claim, finding that the petitioners in that proceeding could not collaterally attack the order in Case No. U-17000. And, in his partial grant of the motion in limine, the ALJ similarly found that issues concerning health, safety, and privacy had been adequately addressed by the Commission in various orders and were therefore settled. The Commission agrees and finds no abuse of discretion in the ALJ's evidentiary rulings on AMI.

B. Rate Implementation Timing

Consumers has not completed the purchase of the Jackson plant but expects to do so at some point during the test period. As discussed above, Consumers requested that final rates in this proceeding include the capital and O&M costs for the Jackson plant, with those costs offset by a credit for that amount. When the Jackson plant is purchased, the credit will be removed. There was no dispute concerning Consumers' proposal; therefore the Commission finds that it should be approved.

THEREFORE, IT IS ORDERED that:

A. Based on this order's findings adopting a 2015-2016 test year, a jurisdictional rate base of $9,160,088,000, an authorized rate of return on common equity of 10.3%, and an authorized overall rate of return of 6.18%, Consumers Energy Company is authorized to implement rates that increase its annual electric revenues by $130,127,000 on a jurisdictional basis over the rates approved in Case No. U-17087 on and after December 1, 2015. After the closing of the sale of the Jackson Power Plant, Consumers Energy Company is authorized to implement rates that increase its annual electric revenues by $164,812,000 on a jurisdictional basis. On and after April 15, 2016, Consumers Energy Company is authorized to implement rates that increase its annual electric revenues by $126,356,000 on a jurisdictional basis. Implementation of these rates will be in three steps, as provided in Ordering Paragraphs B, C, and D.

B. On and after December 1, 2015, Consumers Energy Company is authorized to implement increased rates on a service rendered basis for the distribution and sale of electric energy to its retail customers to produce revenues as summarized in Attachment A and shown in Attachment B. The rates set forth in Attachment B include credits associated with the timing of the closing of Consumers Energy Company's acquisition of the 540 megawatt Jackson Power Plant. Those credits will remain in effect until the Jackson Power Plant purchase closes. On that date, the credits will be terminated and the rates set forth in Attachment B will remain in effect.

C. Within 30 days of November 19, 2015, Consumers Energy Company shall file tariff sheets substantially similar to those contained in Attachment B. Due to the size of Attachment B, it is not physically attached to the original order contained in the official docket or paper copies of the order, but is electronically appended to this order, which is available on the Commission's website.

D. On and after April 15, 2016, Consumers Energy Company is authorized to implement rates on a service rendered basis for the distribution and sale of electric energy to its retail customers to produce revenues as summarized in Attachment C and shown in Attachment D. Within 30 days of that date, Consumers Energy Company shall file tariff sheets substantially similar to those contained in Attachment D. Due to the size of Attachment D, it is not physically attached to the original order contained in the official docket or paper copies of the order, but is electronically appended to this order, which is available on the Commission's website.

E. On or before February 19, 2016, Consumers Energy Company shall file an application for authority to conduct a self-implementation reconciliation proceeding as required under MCL 460.6a(1).

F. Consumers Energy Company's request for authority to implement an Investment Recovery Mechanism is denied.

G. Consumers Energy Company's request for authority to implement a Revenue Adjustment Mechanism is denied.

H. Consumers Energy Company's request for authority to implement a Threat-of-Violence Tariff is denied.

I. Consumers Energy Company is authorized to continue implementation of the advanced metering infrastructure opt out tariff, as described in this order.

J. Within 90 days of the date of this order, the Commission Staff shall initiate a meeting with Consumers Energy Company for the purpose of discussing future analysis of the hazardous tree removal program.

K. Within 90 days of the date of this order, the Commission Staff shall initiate a stand-by rates working group that includes all interested parties, to be conducted in accordance with the directives in this order. Within nine months of the date of this order, the Commission Staff shall submit a report in this docket detailing the findings and conclusions of the stand-by rate working group.

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 the 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

John D. Quackenbush

John D. Quackenbush, Chairman

Sally A. Talberg

Sally A. Talberg, Commissioner, concurring in part and dissenting in part in a separate opinion

Norman J. Saari

Norman J. Saari, Commissioner

By its action of November 19, 2015.

Mary Jo Kunkle

Mary Jo Kunkle, Executive Secretary

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-17735

SEPARATE OPINION OF COMMISSIONER SALLY A. TALBERG CONCURRING, IN PART, AND DISSENTING, IN PART

(Submitted November 19, 2015)

While I concur with the lion's share of the determinations made by my colleagues on the contested issues in this case, I must respectfully dissent from three aspects of the majority's opinion and order. Whereas my colleagues have authorized Consumers to increase its rates by the annual amount of over $126 million, in my judgment Consumers' rate increase should be limited to $93.8 million. I commend my colleagues for the respectful deliberations and effort to reach a consensus on the majority of the issues. I also want to acknowledge Administrative Law Judge Mark E. Cummins for his diligence, and the concise and reasonable proposal for decision that formed the basis of the Commission's decisions.

Return on Equity

I disagree with my colleagues' decision to approve a 10.3% ROE for Consumers. I believe the recommendation in the PFD for use of a 10% ROE is more reasonable based on the record evidence.[10]

MCL 24.285 requires evidentiary support for the Commission's determinations. In my opinion, when weighing the evidence presented regarding any specific issue, the Commission should substantiate its determination with the most influential evidence available rather than upon

[10] Rejection of the PFD's recommendation adds about $19 million to Consumers' jurisdictional revenue deficiency.

a fleeting reference that is not otherwise well supported by the record. In the direct testimony submitted by the parties and throughout the briefing stages, the proffered ROEs were: 10.7% by Consumers; 10% by the Staff; 9.75% by the Attorney General; and 9.6% by ABATE.[11] Actual evidentiary support for use of a 10.3% ROE was almost nonexistent. Staff witness Megginson simply characterized 10.3% as being at the highest end of his range of reasonableness; he did not support its adoption by the Commission. All other parties except Consumers presented evidence and arguments in favor of an ROE below 10%. Consumers witness Rao's lone remarks regarding the reasonableness of the use of an ROE below 10.7% came during his rebuttal testimony in the form of several statements to the effect that "[t]he current equity return of 10.30% is at the low end of what I believe investors view as reasonable for Consumers Energy's electric business." 5 Tr 250. However, Mr. Rao then immediately renewed his support for use of an ROE of 10.7% in this proceeding. 5 Tr 250. It was only after issuance of the PFD, which recommended use of an ROE of 10% to set Consumers' rates, that Consumers effectively abandoned the position taken by its witness, Mr. Rao, by repeatedly asserting in its exceptions and reply to exceptions[12] that the Commission should continue using Consumers' existing 10.3% ROE that had been most recently established via an order approving a settlement agreement in Case No. U-17087.[13] My colleagues acknowledged that "the ALJ provided an excellent analysis of this issue," but then departed from

[11] The Municipal Coalition supported ABATE's 9.6% position in brief, but did not offer any proof of its own during the hearing. Wal-Mart also offered no proof on the ROE issue, opting only to urge rejection of Consumers' position without proposing any alternative value.

[12] Such argumentative assertions in a party's pleadings do not rise to the level of record evidence.

[13] In footnote 7 of the majority's opinion, it is noted that "Consumers does not address its request for a 10.7% ROE in its exceptions." Majority opinion, p. 46.

his well-reasoned recommendation on the appropriate ROE to be used to calculate Consumers' rate increase by using the company's current ROE of 10.3% for this task. Majority opinion, p. 47.

Approval of a 10.3% ROE in Case No. U-17087 should have no legal or evidentiary significance in this proceeding. Paragraph 10 of the settlement agreement attached to the May 15, 2013 order in Case No. U-17087 specifically provides that "neither the parties to this Settlement Agreement nor the Commission shall make any reference to, or use, this Settlement Agreement or the order approving it, as a reason, authority, rationale, or example for taking any action or position or making any subsequent decision in any other case or proceeding" except for enforcement or implementation purposes.

Based on these factors, I am persuaded that the Commission should have set Consumers' ROE at 10%.

Bonus Depreciation

I also disagree with the ALJ's and my colleagues' decision to reject the Staff's position regarding the appropriate treatment of bonus depreciation.[14]

Consumers is owed a tax refund from its parent company due to Congressional action in late 2014 to extend the bonus depreciation provision. Consumers and the Staff each offered differing methodologies regarding how Consumers' 2014 tax refund should be reflected in the instant case, which are centered on Consumers' tax sharing agreement with its parent company. Consumers argued that its normal course of business regarding these matters is to record an intercompany income tax receivable and accordingly chose to project the bonus depreciation refund as an amount due from its parent company. This option causes rates to increase in the instant case. The

[14] Rejection of the Staff's position increases Consumers' revenue deficiency by approximately $10.5 million.

Staff, on the other hand, asserted that under the tax sharing agreement, Consumers could have exercised its right to receive the projected refund prior to the test year[15] and prudently use the refund to pay down its debt and equity in equal portions. The Staff's option causes rates to decrease in the instant case. Even if Consumers decided to wait to obtain the actual refund after taxes were finalized in November 2015, Consumers could have agreed with the Staff methodology in principle by reflecting an estimated refund amount rather than remaining staunch in its position.[16] Consumers is not blindly operating its business and therefore, could estimate, with fairly high precision, an amount to appropriately reflect the refund in rates as it does with its other rate case items using a projected test year.

The primary reason given by both the ALJ and the majority for rejecting the Staff's position on the appropriate treatment of bonus depreciation is that the Staff's position is not consistent with the actual circumstances. The ALJ was critical of the Staff's position because he found it amounted to "speculation" regarding Consumers' treatment of bonus depreciation that was built upon an "incorrect assumption" that the utility had received its share of the IRS refund before the start of the test year. PFD, p. 63.

I find that the thrust of the Staff's position is not on the utility's actual treatment of bonus depreciation to date, but on how the Commission should handle the situation for ratemaking purposes to ensure ratepayers are not disadvantaged. I am convinced that the benefits of bonus depreciation should flow to ratepayers in the manner proposed by the Staff. While it is Consumers' prerogative to operate its business as it deems appropriate, the company's decision on

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[15] And, if needed, the company could reconcile that amount with the actual refund after taxes are finalized. *See*, Staff Exhibits S-20 and S-26.

[16] The Staff's bonus depreciation methodology as proposed in this case was adopted by DTE Electric Company without opposition in its rate case (Case No. U-17767).

bonus depreciation adversely impacted ratepayers and could have been avoided. The Commission should not insert itself into management decisions, but it certainly has a right and a duty to ensure that rates are based on reasonable inputs and to balance management decisions with what is ultimately best for ratepayers. Unlike Consumers' approach, the Staff's method would have held ratepayers harmless.

The Staff's argument that the Commission may, for ratemaking purposes, hypothesize how to best protect ratepayers or the utility under unusual circumstances is clearly supported by precedent. One example is the situation wherein Consumers was seeking an increase in its rates for the sale and distribution of natural gas in Case No. U-8924.[17] In 1989, Consumers' current capital structure was so distorted by major write-offs of investments and by debt restructuring activities that both the utility and the Staff supported the use of a hypothetical capital structure. Ultimately, in an order issued on December 7, 1989 in Case Nos. U-8678, U-8924, and U-9197, the Commission opted to use Michigan Consolidated Gas Company's actual capital structure as a proxy for that of Consumers.

For these reasons, I find that the Staff's position on the ratemaking treatment of bonus depreciation has merit, and should have been followed in this proceeding.

<u>Employee Incentive Compensation</u>

Finally, although I am generally inclined to support the concept of performance-based employee compensation models, I am hesitant to fully endorse the majority opinion's determination on this issue. It appears that Consumers' evidentiary presentation on the overall

[17] Consumers was known as Consumers Power Company in Case No. U-8924.

levels of compensation was not challenged on the record.[18] Likewise, I do not oppose the majority's decision to include in rates some form of incentive compensation if it can be shown to benefit customers. However, at this juncture I am persuaded that the Commission should limit such recovery from ratepayers to amounts undisputedly linked to utility operating performance metrics meant to benefit customer service. Linking the ratepayers' obligation to fund employee incentive compensation to performance metrics that will have a direct effect on customer experience and satisfaction is reasonable. Linkage to the financial metrics that mostly benefit the company's investors does not, in my opinion, pass muster. While it is no doubt important for customers to maintain a financially healthy utility, it seems logical at this point to require customers to support customer-oriented outcomes and for the shareholders to support short- and long-term financial outcomes. Consumers' performance metrics more heavily value financial results as evidenced by the breakdown of how compensation is disbursed and the fact that its officers do not receive any incentive compensation if the financial outcomes are not met.[19]

[18] This is different from Consumers providing benchmarking data and other references (e.g., studies of compensation levels among peer organizations) to convincingly support its expert's claim that the compensation levels are reasonable. The limited information provided to the Commission makes it difficult for the Commission to fully assess the reasonableness of total compensation levels.

[19] *See*, Staff Exhibit S-11.19.

Moreover, limiting recovery from ratepayers to customer-oriented outcomes (i.e., $2 million instead of the $5 million approved by the majority) is a more cautious approach as we alter our regulatory policy after over a decade of the Commission consistently relieving ratepayers from funding all such employee incentive compensation.

MICHIGAN PUBLIC SERVICE COMMISSION

Sally A. Talberg, Commissioner

MICHIGAN PUBLIC SERVICE COMMISSION

Case No.: U-17735
Attachment A
Page: 1 of 3

Consumers Energy Company
Summary of Present and Proposed Revenues by Rate Schedule

Total Revenues

Line No.	Description	(a) Sales	(b) Present Revenue	(c) Proposed Revenue	(d) Difference Revenue	(e) Difference Percent
		MWh	$000	$000	$000	%
	Bundled Service					
	Residential Class					
1	Residential Service RS	12,386,521	$ 1,756,640	$ 1,897,054	$ 140,414	8.0
2	Residential Time-of-Day RT	49,576	6,393	6,722	329	5.2
3	Residential Electric Vehicle REV	3,161	354	398	44	12.5
4	Res. Dynamic Price RSDP	-	-	-	-	NA
5	Res. Dynamic Price Rebate RSDPR	-	-	-	-	NA
6	Total Residential Class	12,439,258	1,763,387	1,904,174	140,788	8.0
	Secondary Class					
7	Secondary Energy-only GS	3,474,949	504,176	528,758	24,582	4.9
8	Sec. Energy Dynamic Price GSDP	-	-	-	-	NA
9	Secondary Demand GSD	4,017,015	498,550	518,493	19,943	4.0
10	Sec. Demand Dynamic Price GSDDP	-	-	-	-	NA
11	Total Secondary Class	7,491,964	1,002,726	1,047,250	44,524	4.4
	Primary Class					
12	Primary Energy-only GP	1,407,804	147,950	154,015	6,065	4.1
13	Pri. Energy Dynamic Price GPDP	-	-	-	-	NA
14	Primary Demand GPD	9,343,402	824,298	806,624	(17,673)	(2.1)
15	Primary Energy Intensive Rate EIP/MMPP	355,201	22,424	22,213	(211)	(0.9)
16	Primary Time of Use Pilot GPTU	205,807	18,165	19,199	1,034	5.7
17	Large Economic Development E-1[1]	1,778,677	102,212	113,792	11,580	11.3
18	Total Primary Class	13,090,891	1,115,048	1,115,843	795	0.1
		11,312,214	1,012,836 -	1,002,051		
	Lighting & Unmetered Class					
19	Metered Lighting Service GML	8,058	900	914	15	1.6
20	Unmetered Lighting Service GUL	131,024	30,303	28,414	(1,889)	(6.2)
21	Unmetered Exp. Lighting GU-XL	-	-	-	-	NA
22	Unmetered Service GU	86,458	7,751	7,679	(72)	(0.9)
23	Total Lighting & Unmetered Class	225,540	38,954	37,008	(1,946)	(5.0)
	Self-generation Class					
24	Small Self-generation GSG-1	-	-	-	-	NA
25	Large Self-generation GSG-2	46,865	3,207	1,529	(1,678)	(52.3)
26	Total Self-Generation Class	46,865	3,207	1,529	(1,678)	(52.3)
27	Total Bundled Service	33,294,517	$ 3,923,322	$ 4,105,805	$ 182,482	4.7
	ROA Service					
	Residential Class					
28	Residential Service RS	-	$ -	$ -	$ -	NA
29	Residential Time-of-Day RT	-	-	-	-	NA
30	Total Residential Class	-	-	-	-	NA
	Secondary Class					
31	Secondary Energy-only GS	24,640	936	1,060	124	13.3
32	Secondary Demand GSD	210,891	6,375	7,172	798	12.5
33	Total Secondary Class	235,532	7,311	8,233	922	12.6
	Primary Class					
34	Primary Energy-only GP	51,324	813	881	68	8.4
35	Primary Demand GPD	3,779,243	26,871	21,856	(5,015)	(18.7)
36	Total Primary Class	3,830,567	27,684	22,737	(4,947)	(17.9)
37	Total ROA Service	4,066,098	$ 34,995	$ 30,970	$ (4,025)	(11.5)
38	Total Bundled and ROA Service	37,360,615	$ 3,958,317	$ 4,136,775	$ 178,458	4.5

[1] Present Revenue reflects a 5/1/15 - 11/30/15 at E-1 rate, remaining at present GPD, proposed revenue reflects a full year at the proposed GPD rates

MICHIGAN PUBLIC SERVICE COMMISSION

Consumers Energy Company
Summary of Present and Proposed Revenues by Rate Schedule

Power Supply Revenues

Line No.	Description	(a) Sales	(b) Present Revenue	(c) Proposed Revenue	(d) Difference Revenue	(e) Difference Percent
		MWh	$000	$000	$000	%
	Bundled Service					
	Residential Class					
1	Residential Service RS	12,386,521	$ 1,104,717	$ 1,224,458	$ 119,741	10.8
2	Residential Time-of-Day RT	49,576	4,082	4,329	247	6.0
3	Residential Electric Vehicle REV	3,161	183	222	39	21.2
4	Res. Dynamic Price RSDP	-	-	-	-	NA
5	Res. Dynamic Price Rebate RSDPR	-	-	-	-	NA
6	Total Residential Class	12,439,258	1,108,982	1,229,008	120,026	10.8
	Secondary Class					
7	Secondary Energy-only GS	3,474,949	330,289	336,041	5,753	1.7
8	Sec. Energy Dynamic Price GSDP	-	-	-	-	NA
9	Secondary Demand GSD	4,017,015	371,912	376,675	4,763	1.3
10	Sec. Demand Dynamic Price GSDDP	-	-	-	-	NA
11	Total Secondary Class	7,491,964	702,200	712,716	10,516	1.5
	Primary Class					
12	Primary Energy-only GP	1,407,804	124,867	128,904	4,037	3.2
13	Pri. Energy Dynamic Price GPDP	-	-	-	-	NA
14	Primary Demand GPD	9,343,402	744,848	737,685	(7,163)	(1.0)
15	Primary Energy Intensive Rate EIP/MMPP	355,201	21,206	21,020	(186)	(0.9)
16	Primary Time of Use Pilot GPTU	205,807	15,827	16,541	713	4.5
17	Large Economic Development E-1	1,778,677	84,240	133,106	48,866	58.0
18	Total Primary Class	13,090,891	990,987	1,037,255	46,268	4.7
	Lighting & Unmetered Class					
19	Metered Lighting Service GML	8,058	458	441	(18)	(3.8)
20	Unmetered Lighting Service GUL	131,024	8,000	6,853	(1,147)	(14.3)
21	Unmetered Exp. Lighting GU-XL	-	-	-	-	NA
22	Unmetered Service GU	86,458	6,637	6,420	(218)	(3.3)
23	Total Lighting & Unmetered Class	225,540	15,095	13,714	(1,382)	(9.2)
	Self-generation Class					
24	Small Self-generation GSG-1	-	-	-	-	NA
25	Large Self-generation GSG-2	46,865	2,512	-	(2,512)	(100.0)
26	Total Self-Generation Class	46,865	2,512	-	(2,512)	(100.0)
27	Total Bundled Service	33,294,517	$ 2,819,777	$ 2,992,693	$ 172,916	6.1
	ROA Service					
	Residential Class					
28	Residential Service RS	-	$ -	$ -	$ -	NA
29	Residential Time-of-Day RT	-	-	-	-	NA
30	Total Residential Class	-	-	-	-	NA
	Secondary Class					
31	Secondary Energy-only GS	24,640	-	-	-	NA
32	Secondary Demand GSD	210,891	-	-	-	NA
33	Total Secondary Class	235,532	-	-	-	NA
	Primary Class					
34	Primary Energy-only GP	51,324	-	-	-	NA
35	Primary Demand GPD	3,779,243	-	-	-	NA
36	Total Primary Class	3,830,567	-	-	-	NA
37	Total ROA Service	4,066,098	$ -	$ -	$ -	NA
38	Total Bundled and ROA Service	37,360,615	$ 2,819,777	$ 2,992,693	$ 172,916	6.1

MICHIGAN PUBLIC SERVICE COMMISSION

Consumers Energy Company
Summary of Present and Proposed Revenues by Rate Schedule

Delivery Revenues

Line No.	Description	(a) Sales	(b) Present Revenue	(c) Proposed Revenue	(d) Difference Revenue	(e) Difference Percent
		MWh	$000	$000	$000	%
	Bundled Service					
	Residential Class					
1	Residential Service RS	12,386,521	$ 651,923	$ 672,596	$ 20,673	3.2
2	Residential Time-of-Day RT	49,576	2,310	2,393	83	3.6
3	Residential Electric Vehicle REV	3,161	171	176	5	3.1
4	Res. Dynamic Price RSDP	-	-	-	-	NA
5	Res. Dynamic Price Rebate RSDPR	-	-	-	-	NA
6	Total Residential Class	12,439,258	$ 654,405	675,166	20,761	3.2
	Secondary Class					
7	Secondary Energy-only GS	3,474,949	173,888	192,717	18,829	10.8
8	Sec. Energy Dynamic Price GSDP	-	-	-	-	NA
9	Secondary Demand GSD	4,017,015	126,638	141,818	15,180	12.0
10	Sec. Demand Dynamic Price GSDDP	-	-	-	-	NA
11	Total Secondary Class	7,491,964	300,526	334,534	34,009	11.3
	Primary Class					
12	Primary Energy-only GP	1,407,804	23,083	25,111	2,028	8.8
13	Pri. Energy Dynamic Price GPDP	-	-	-	-	NA
14	Primary Demand GPD	9,343,402	79,449	68,939	(10,510)	(13.2)
15	Primary Energy Intensive Rate EIP/MMPP	355,201	1,218	1,193	(25)	(2.1)
16	Primary Time of Use Pilot GPTU	205,807	2,338	2,658	321	13.7
17	Large Economic Development E-1	1,778,677	17,972	(19,314)	(37,286)	(207.5)
18	Total Primary Class	13,090,891	124,061	78,588	(45,473)	(36.7)
	Lighting & Unmetered Class					
19	Metered Lighting Service GML	8,058	442	474	32	7.3
20	Unmetered Lighting Service GUL	131,024	22,303	21,561	(742)	(3.3)
21	Unmetered Exp. Lighting GU-XL	-	-	-	-	NA
22	Unmetered Service GU	86,458	1,114	1,260	146	13.1
23	Total Lighting & Unmetered Class	225,540	23,859	23,294	(564)	(2.4)
	Self-generation Class					
24	Small Self-generation GSG-1	-	-	-	-	NA
25	Large Self-generation GSG-2	46,865	695	1,529	834	119.9
26	Total Self-Generation Class	46,865	695	1,529	834	119.9
27	Total Bundled Service	33,294,517	$ 1,103,545	$ 1,113,112	$ 9,566	0.9
	ROA Service					
	Residential Class					
28	Residential Service RS	-	$ -	$ -	$ -	NA
29	Residential Time-of-Day RT	-	-	-	-	NA
30	Total Residential Class	-	-	-	-	NA
	Secondary Class					
31	Secondary Energy-only GS	24,640	936	1,060	124	13.3
32	Secondary Demand GSD	210,891	6,375	7,172	798	12.5
33	Total Secondary Class	235,532	7,311	8,233	922	12.6
	Primary Class					
34	Primary Energy-only GP	51,324	813	881	68	8.4
35	Primary Demand GPD	3,779,243	26,871	21,856	(5,015)	(18.7)
36	Total Primary Class	3,830,567	27,684	22,737	(4,947)	(17.9)
37	Total ROA Service	4,066,098	$ 34,995	$ 30,970	$ (4,025)	(11.5)
38	Total Bundled and ROA Service	37,360,615	$ 1,138,540	$ 1,144,082	$ 5,541	0.5

INDEX

(Continued From Sheet No. A-4.00)

SECTION D
RATE SCHEDULES (Contd)

(Continued on Sheet No. A-6.00)

TECHNICAL TERMS AND ABBREVIATIONS
(FOR ALL CUSTOMERS)

I. The definitions of the following technical terms and abbreviations are applicable to the Company's Electric Rate Book and are not contained in the other Sections thereof:

A. For All Utilities

(1) "Commission" means the Michigan public service commission.
(2) "Effective Date" means the date when the tariff sheet must be followed.
(3) "Issue Date" means the date the Company files a tariff sheet with the Commission.
(4) "Rate Book" means the complete set of Company filings submitted in accordance with the "Filing Procedures for Electric, Wastewater, Steam and Gas Utilities".
(5) "Rate Schedule" or "Rider" means the rate or charge for a particular classification of service, including all special terms and conditions under which that service is furnished at the prescribed rate or charge.
(6) "Rate Sheet" or "Tariff Sheet" means any of the documents filed in accordance with "Filing Procedures for Electric, Wastewater, Steam and Gas Utilities".
(7) "Rules and Regulations" means the rules, regulations, practices, classifications, exceptions, and conditions that the Company must observe when providing service.
(8) "Standard Customer Forms Index" means a listing showing the number, title, and revision date for all standard forms, in any format (preprinted or electronically preformatted) that the Company uses to document contracts or other agreements that create or alter a customer's rights or responsibilities in dealings with the Company. Standard customer forms require a customer signature or are specifically referenced within the Rate Book for execution between the Company and customers.

B. Company

Advance - For the purposes of deposits and contributions, "in advance" means in advance of commencement of construction.

Ampere (A) - Unit of electrical current produced in a circuit by one volt acting across resistance of one ohm. It is also proportional to the quantity of electrons flowing through a conductor past a given point in one second.

Bona Fide Change in Customer Load - A change in customer load made in good faith without fraud or deceit.

Commercial Usage for Emergency Electrical Procedures - Usage for applications, other than residential, associated with businesses and other establishments which qualify for a nonmanufacturing industry code under the most current edition of the Standard Industrial Classification Manual. In addition to the usual retail and service businesses included are communication, transportation, utility, recreation, education, religious, social and governmental businesses or institutions. It also includes usage for business offices and common use facilities associated with centrally metered complexes (apartments, condominiums, and trailer parks).

Company - Consumers Energy Company.

Customer Voltage Level 1 – Service supplied either directly from the Company's distribution system when the voltage is 120,000 Volts or greater or from this system through a Company-owned substation where, from the exits of the substation, the distribution equipment for supplying service is owned and maintained by the customer.

(Continued on Sheet No. A-30.00)

(Continued From Sheet No. C-1.00)

C1. CHARACTERISTICS OF SERVICE (Contd)

C1.3 Use of Service

The customer shall use the service so as not to cause a safety hazard, endanger the Company facilities or the customer's equipment or to disturb the Company's service to other customers. The Company disclaims any responsibility to inspect the customer's wiring or equipment and shall not be held liable for any injury, damage or overbilling resulting from the condition thereof, or from any of the circumstances described in Paragraphs A through O below in this rule.

The Company reserves the right to deny or shut off service in accordance with Rules and Regulations of the Company or Commission under the following conditions or for any of the following reasons:

A. Without prior notice to any customer for a condition on the customer's premises which is determined by the Company or a code authority to be hazardous.

B. Without prior notice if the customer uses equipment in a manner which adversely affects the Company's equipment or the Company's service to others.

C. To any customer involved in metered or unmetered energy theft, including obtaining the use of equipment by submitting a falsified application. Energy theft includes but is not limited to:

(1) Tampering
(2) Unauthorized Use
(3) Diversion
(4) Interference

D. For misrepresentation of identity for the purpose of obtaining utility service.

E. For failure of the customer to permit the Company reasonable access to equipment installed upon the premises for the purpose of inspection, meter reading, maintenance, replacement or removal.

F. For failure of the customer to install and/or maintain necessary devices to protect his/her equipment in the event of service interruptions and other disturbances on the Company's Distribution system.

G. For failure of the customer to install and/or maintain necessary devices to protect the Company's facilities against overload caused by the customer's equipment.

H. For failure of the customer to fulfill contractual obligations for service or facilities.

I. For failure of the customer to obtain all permits and inspections of customer's wiring or equipment required by applicable law.

J. For failure of the reselling customer to comply with Rule C4.4, Resale.

K. For failure of the customer to post a cash security deposit or other form of guarantee, when required in accordance with these Rules and Regulations.

L. For failure of the customer to pay a delinquent account not in dispute.

(Continued on Sheet No. C-3.00)

(Continued From Sheet No. C-3.00)

C1. CHARACTERISTICS OF SERVICE (Contd)

C1.4 Extraordinary Facility Requirements and Charges (contd)

Contribution In Aid of Construction Allowance Schedule

		With a Full Service Contract, by Contract Duration					Without Full Service Contract
Schedule	Customer Voltage Level(CVL)	1 Year	2 Year	3 Year	4 Year	5 Year	
General Service Primary Rate GP	1	$*0.024*/kWh	$*0.034*/kWh	$*0.049*/kWh	$*0.064*/kWh	$*0.077*/kWh	$*0.024*/kWh
	2	$*0.032*/kWh	$*0.045*/kWh	$*0.065*/kWh	$*0.084*/kWh	$*0.101*/kWh	$*0.032*/kWh
	3	$*0.051*/kWh	$*0.055*/kWh	$*0.080*/kWh	$*0.103*/ kWh	$*0.124*/kWh	$*0.051*/kWh
General Service Primary Demand Rate GPD	1	$*30*/kW	$*55*/kW	$*80*/kW	$*100*/kW	$*120*/kW	$*25*/Kw
	2	$*80*/kW	$*135*/kW	$*195*/kW	$*250*/kW	$*300*/kW	$*80*/kW
	3	$*140*/kW	$*185*/kW	$*270*/kW	$*345*/kW	$*420*/kW	$*140*/kW
Energy Intensive Primary Rate *EIP*	1	$*0*/kW	$*0*/kW	$*0*/kW	$*0*/kW	$*0*/kW	NA
	2	$*25*/kW	$*50*/kW	$*70*/kW	$*90*/kW	$*110*/kW	NA
	3	$*65*/kW	$*120*/kW	$*175*/kW	$*225*/kW	$*270*/kW	NA

The Company reserves the right to make special contractual arrangements as to the provision of necessary Service Facilities, duration of contract, minimum bills, require upfront deposit and other service conditions, including, but not limited to, when the customer's load requirements are of a short-term duration, temporary or a transient nature, or if in the opinion of the Company, the customer does not have acceptable credit history or represents an unacceptable credit risk or other reasons within the sound discretion of the Company.

C1.5 Invalidity of Oral Agreements or Representations

When a written contract is required, no employee or agent of the Company is authorized to modify or supplement the Rules and Regulations and Rate Schedules of the Electric Rate Book by oral agreement or representation, and no such oral agreement or representation shall be binding upon the Company.

(Continued on Sheet No. C-4.00)

(Continued From Sheet No. C-19.00)

C4. APPLICATION OF RATES (Contd)

C4.2 Choice of Rates (Contd)

After the customer has selected the rate and rate provision under which service shall be provided, the customer shall not be permitted to change from that rate and rate provision to another until at least twelve months have elapsed. The customer shall not be permitted to evade this rule by temporarily terminating service. However, the Company may, at its option, waive the provisions of this paragraph where it appears a change is for permanent rather than for temporary or seasonal advantage. The provisions of this paragraph may also be waived where the customer can demonstrate that a Bona Fide Change in Customer Load has occurred. The effective date of a rate change under this rule shall be the beginning read date of the next bill issued. The intent of this rule is to prohibit frequent shifts from rate to rate.

The Company shall not make refunds in instances where the customer would have paid less for service had the customer been billed on another applicable rate or provision rate.

Where the customer has provided the Company with incorrect information to gain an economic benefit, backbilling may be rendered to the date the incorrect rate selection initially occurred.

In order to reduce load in times of high system demands, the Company may make contractual arrangements with customers who can self-generate power, shift load from on-peak to off-peak periods and/or provide other forms of voluntary load reduction.

C4.3 Application of Residential Usage and Non-Residential Usage

A. Residential Usage and Rate Application

(1) General

For purposes of rate application "residential usage" shall be usage metered and consumed within an individual household, and reasonably appurtenant and related to and normally associated with such a household, for such applications as space conditioning, cooking, water heating, refrigeration, clothes drying, incineration, lighting and other similar household applications.

The term "household" includes single-family homes, farm homes, seasonal dwellings, duplexes, and individual living units within mobile home parks, condominiums, apartments and cooperatives; provided, however, to qualify for residential usage a household must have the normal household facilities such as bathroom, individual cooking and kitchen sink facilities and have received an occupancy permit or similar instrument, if issued, by the local governing authority. *Customers requiring temporary electric service for a residential dwelling under construction shall be served under the General Service Secondary Rate GS – Commercial – Temporary Construction Service until a permit for occupancy is obtained for the premises.*

At the time a new service or a rate change is requested, the Company shall advise the customer in the selection of the rate or rate provision which will give the customer the lowest cost of service based on the information provided to the Company. The Company's recommendation will be based upon the customer's energy usage and responses to the following criteria: (a) type of dwelling, (b) meets the requirements for Income Assistance Service Provision, and (c) meets the requirements for Senior Citizen Service Provision.

(Continued on Sheet No. C-21.00)

(Continued From Sheet No. C-21.00)

C4. APPLICATION OF RATES (Contd)

C4.3 Application of Residential Usage and Non-Residential Usage (Contd)

A. Residential Usage and Rate Application (Contd)

(c) Multifamily Dwellings Served Through a Single Meter

A multifamily dwelling served through a single meter shall be billed as follows:

(i) Dwellings containing two households, including common area, shall be billed on Residential Service Secondary Rate RS.

(ii) Dwellings containing three or four households, including common area, shall be billed on Residential Service Secondary Rate RS or the appropriate General Service Rate.

(iii) Dwellings containing five or more households, including common area, shall be billed on the appropriate General Service Rate.

(5) Farm Service

Service shall be available to farms for residential use under the appropriate Residential Service Secondary Rate. *Service* may be used through the same meter so long as such use is confined to single-phase or three-phase secondary service where electric energy is used for the culture, processing and handling of products grown or used on the customer's farm. The qualifying small farm customer must be the owner and operator of the farm, a physical occupant of the main household which is used as the customer’s principal residence, and the associated farm buildings/facilities must be located on the same premises as the main household. Use of service for purposes other than set forth above shall be served and billed on the appropriate General Service Rate.

In general, the entire electrical needs of the farm operation and residence on a single premises shall be served through a single meter. A second meter on a General Service Rate may be allowed on the premises for a portion of the farm operation if a representative of the Company determines that it is impractical to serve the load through a single metering installation.

B. Non-Residential Usage and Rate Application

For purposes of rate application, "Non-Residential usage" shall be usage metered and consumed that does not qualify for residential usage. Non-Residential usage includes usage associated with the purchase, sale, or supplying (for profit or otherwise) of a commodity or service by a public or private person, entity, organization or institution. Non-Residential usage includes usage associated with penal institutions, corrective institutions, motels, hotels, separately metered swimming pool heater usage, yachts, boats, tents, campers or recreational vehicles.

Non-Residential usage shall be billed on the Company's appropriate General Service Rate.

Tourist homes, rooming houses, dormitories, nursing homes and other similarly occupied buildings containing sleeping accommodations for more than six persons shall be classified as Non-Residential and billed on the appropriate General Service Rate. The landlord and his/her immediate family are not included in the six-person rule.

Rules for Multifamily Dwellings and Farm Service can be found in Sections A(4) and (5) of this rule.

(Continued on Sheet No. C-23.00)

(Continued From Sheet No. C-23.00)

C4. APPLICATION OF RATES (Contd)

C4.3 Application of Residential Usage and Non-Residential Usage (Contd)

D. Rate Application for Seasonal Condominium Campgrounds (Contd)

(5) The customer must notify individuals and/or co-owners utilizing the customer's property that the customer's facilities may not be able to be located by Miss Dig.

(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 Demand Rate GSD, General Service Primary Rate GP, or General Service Primary Demand Rate GPD. 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 RS 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, Residential Service Time-of-Day Secondary Rate RT 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:

$*0.146832* per kWh for all kWh during the months of June-September
$*0.139253* 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-25.00)

(Continued From Sheet No. C-24.00)

C4. APPLICATION OF RATES (Contd)

C4.4 Resale (Contd)

The service contract shall also provide that the reselling customer shall be responsible for the testing of each ultimate user's meter at least once every 3 years. The accuracy of such meters shall be maintained within the limits as prescribed in Rule B1., Technical Standards for Electric Service. Meters shall be tested only by outside testing services or laboratories approved by the Company.

A record of each meter, including testing results, shall be kept by the reselling customer during use of the meter and for an additional period of one year thereafter. When requested, the reselling customer shall submit certified copies of the meter test results and meter records to the Company.

The reselling customer shall supply each ultimate user with an electric system adequate to meet the needs of the ultimate user with respect to the nature of service, voltage level and other conditions of service. The reselling customer shall render a bill once during each billing month to each of the customer's tenants in accordance with approved Rate Schedules of the Company. Every bill rendered by the reselling customer shall specify the following information: the rate categories and provisions; the due date; the beginning and ending meter readings of the billing period and dates thereof; the difference between the meter readings; the Power Supply Cost Recovery Factor; if applicable; the subtotal of the bill before taxes; amount of sales tax; other local taxes where applicable; any previous balance; the amount due for delivery service and/or power supply service, as applicable; the amount due for other authorized charges; and the total amount due. The due date of the customer's bill shall be 21 days from the date of rendition.

If the reselling customer fails to meet the obligations of this rule, the Company shall notify the Commission. If, after review with the reselling customer, the problem is not resolved, the Company shall assess a penalty in the amount of 2% of the resale customer's bill before taxes per month *until the problem is resolved*. If the problem is not resolved after three months, the Company shall shut off electric service until the problem is resolved. The Company shall not incur any liability as the result of this shutoff of electric service.

The renting of premises with the cost of electric service included in the rental as an incident of tenancy is not considered to be a resale of such service.

C4.5 Mobile Home Park - Individually Served

For purposes of this rule, the definition of a mobile home park is a parcel or tract of land upon which three or more mobile homes are located on a continuous nonrecreational basis.

Service to separately metered mobile homes shall be billed on the appropriate Residential Service Rate under the following conditions:

Service to all new mobile home parks and expanded service to existing mobile home parks receiving electrical service shall be provided through individual tenant metering.

The mobile home park shall be of a permanent nature with improved streets and with individual water and sewer connections to each lot. Ordinarily, electric service to a mobile home shall be in the name of the occupant. However, service to lots designated for occasional or short-term occupancy shall be in the name of the owner of the park or his/her authorized representative.

(Continued on Sheet No. C-26.00)

(Continued From Sheet No. C-30.00)

C5. CUSTOMER RESPONSIBILITIES (Contd)

C5.2 Bills and Payments (Contd)

J. Energy Theft, Stolen Meter and Switched Meter

In cases where metered or unmetered energy theft, stolen meter or switched meter by someone other than a Company representative are involved, refunds and backbillings are for the determined duration of the period. Where the duration cannot be reasonably established or estimated, the Company will adjust the billing for the past three years on the basis of actual monthly consumption determined from the most recent 36 months of consumption data.

Metered or unmetered energy theft includes but is not limited to tampering, unauthorized use, diversion and interference. For purposes of this rule, a stolen meter is classified as any meter not specifically assigned to that service location by the Company. For purposes of this rule, a switched meter is classified as a meter intentionally assigned incorrectly to a customer resulting in the customer being billed for another customer's consumption.

The Company reserves the right to recover all unbilled service revenue and reasonable actual costs associated with the theft of energy, stolen meters or switched meters. Therefore, the customer or other user who benefits from the unauthorized or fraudulent use is responsible for payment of the reasonable actual cost of the service used during the period such fraudulent or unauthorized use or tampering occurred, or is reasonably assumed to have occurred, and is responsible for the reasonable actual cost of the tampering investigation and any associated damages, with the exception that all costs be recovered in cases involving criminal prosecution. The customer who did not intentionally steal a meter, switch a meter or who did not intentionally become involved in energy theft shall pay for energy usage according to Section H of this rule.

The owner of the multiple metered building shall be responsible for accurately tracing all lines and for tagging such lines with Company-provided tags to assure individual units are properly metered. The Company will not set the meters until the lines are identified. The owner of the multiple metered building could be held responsible for any underrecovery of revenues resulting from improperly tagged meters. Any future expense of tracing lines due to instances of switched meters related to errors in tracing and tagging of such lines shall be the responsibility of the current owner of the multiple metered building.

C5.3 Restoration of Service

Restoration charges and meter relocation charges shall be made by the Company to partially cover the cost of shutting off, terminating and restoring service.

Where service has been shut off for reasons as outlined in Rule C1.3, Use of Service, a restoration charge of $50 shall be collected from the customer whose service was disconnected at the customer's meter. If service was disconnected at the point of contact with the Company's distribution system, a charge of $80 shall be collected from the customer whose service was shut off.

Where service has been shut off for reasons as outlined in Rule C1.3, Use of Service, a meter relocation charge, if applicable, and assessed in accordance with Rule B2., Consumer Standards and Billing Practices for Electric and Gas Residential Service, R 460.116, Meter Accuracy, Meter Errors, Meter Relocations, and R 460.144, Restoration of Service, shall be collected from the customer whose service was shut off. The Company shall charge the customer for relocating the meter, based on the Company's current cost.

(Continued on Sheet No. 32.00)

(Continued From Sheet No. C-31.00)

C5. CUSTOMER RESPONSIBILITIES (Contd)

C5.3 Restoration of Service (Contd)

The restoration charge and meter relocation charge, if applicable, shall be billed to the customer and shall be paid before service is restored.

An On-Premises *Site Visit* Charge of $15.00 shall be assessed to the customer if a Company employee is sent to the premises to either serve the customer with a shut-off notification or to shut off service, unless the customer presents evidence that reasonably indicates the claim has been satisfied or is currently In Dispute. The *charge shall be applied* to the customer account. The Company shall not assess this fee twice on the same notice for shutoff.

In case of shutoff of service, the Company shall restore service only after any metering changes, where deemed necessary by the Company, have been made by the Company and after the customer has paid for any unmetered energy used, paid for any damage to Company property, paid the restoration charge and meter relocation charge, installed any necessary devices to protect the Company's facilities and paid all charges as provided in the Company's Electric Rate Book.

A customer who orders a termination and a restoration of service at the same premises within a 12-month period shall be liable for a "turnon" charge of $50.

C5.4 Shutoff Protection Plan for Residential Customers

A. Eligibility

Eligible low-income customers and senior citizen customers may choose to participate in the Shutoff Protection Plan (SPP) in lieu of the applicable Winter Protection Plan as described in Rule B2., Consumer Standards and Billing Practices for Electric and Gas Residential Service, R 460.148, Winter Protection Plan for Low-income Customers, or R 460.149, Winter Protection Plan for Senior Citizens. For purposes of this Company rule, an eligible low-income customer means a utility customer who has not had more than one default condition on the SPP in the last twelve months and whose household income does not exceed 200% of the federal poverty guidelines as published by the United States Department of Health and Human Services or who receives supplemental security income or low-income assistance through the Department of Human Services or successor agency, food stamps, or Medicaid. In addition, an eligible senior citizen customer means a utility customer who has not had more than one default condition on the SPP in the last twelve months, is 65 years of age or older, and advises the utility of his or her eligibility. An eligible customer enrolled in the SPP shall be referred to as an SPP Customer. Customers who are actively participating in the Consumers Affordable Resource for Energy (CARE) Pilot or have participated in the CARE Pilot during the concurrent heating season are not eligible to participate in SPP until the beginning of the next heating season.

(Continued on Sheet No. C-32.10)

(Continued From Sheet No. C-32.10)

C5. CUSTOMER RESPONSIBILITIES (Contd)

C5.4 Shutoff Protection Plan for Residential Customers (Contd)

D. Default

Should a SPP Customer fail to make payment by the due date, a shutoff notice specific to this SPP shall be issued but shall comply with the requirements of Part 8 of Rule B2., Consumer Standards and Billing Practices for Electric and Gas Residential Service. If the SPP Customer makes payment before the date provided for shutoff of service, the customer shall not be considered to be in default but shall remain in the SPP. If the SPP Customer makes payment after this date, the SPP Customer shall be in default and shall be removed from the SPP. The customer shall be subject to shutoff, provided the 24-hour notice was made by the Company.

E. Participation in Other Shutoff Protection Plans

Customers eligible to participate under the Winter Protection Plan, Rules R 460.148 and R 460.149, will be required to waive their rights to participate under the Winter Protection Plan in order to participate in the Plan. Upon enrollment, the Company shall send written confirmation of the enrollment terms and include notice of this provision.

C5.5 Non-Transmitting Meter Provision

Customers served on Residential Service Secondary Rates RS and General Service Secondary Rates GS have the option to choose a non-transmitting meter.

In order for a customer to be eligible to participate in the Non-Transmitting Meter Provision, the customer must have a meter that is accessible to Company employees and the customer shall have zero instances of unauthorized use, theft, fraud and/or threats of violence toward Company employees.

Customers electing a non-transmitting meter will pay the following charges per premises:

Up Front Charge:	$ 69.39	a one-time charge per premise per request if the notice is given before the transmitting meter is installed
	OR	
	$123.91	a one-time charge per premise per request if the notice is given after the transmitting meter is installed
Monthly Charge:	$ 9.72	per month at each premise

All standard charges and provisions of the customer's applicable tariff shall apply.

(Continued on Sheet No. C-32.30)

(Continued From Sheet No. *C-32.30*)

C6. DISTRIBUTION SYSTEMS, LINE EXTENSIONS AND SERVICE CONNECTIONS (Contd)

C6.1 Overhead Extension Policy (Contd)

A. Residential Customers (contd)

The Company shall make a one-time refund, five years from the completion date of the extension or upon completion of the customer's construction, whichever the customer chooses, of $500 for each additional residential customer and/or the first year's estimated revenue for each additional General Service customer who connects directly to the line for which a deposit was required. Refund allowances shall first be credited against the 25% reduction before a refund is made to the customer based on the customer's cash deposit. Directly connected customers are those who do not require the construction of more than 300 feet of Primary and/or Secondary distribution line. Refunds shall not include any amount of contribution in aid of construction for underground service made under the provisions of Rule C6.2, Underground Policy.

B. General Service Customers

The Company shall construct single-phase and three-phase distribution line extensions, at its own cost when the cost of such extension does not exceed three times the estimated annual revenue from the customer(s) to be immediately served.

Extensions in excess of the above free allowance shall require a deposit from the customer, in an amount equal to the estimated construction costs in excess of the free allowance.

(1) Original Customers

At the end of the first complete 12-month period beginning the month following the date the line extension is completed, the Company shall refund to the depositor three times the amount that actual revenue exceeds the original revenue estimate. If the actual revenue exceeds the estimated revenue, the actual revenue then becomes the base upon which future refund calculations are to be made during the remainder of the five-year refund period.

(2) Additional Connected Customers

The Company shall refund $500 for each residential customer and/or the first year's estimated revenue for each General Service customer who connects directly to the line for which a deposit was required. Directly connected customers are those who do not require the construction of more than 300 feet of Primary and/or Secondary distribution line. Refunds shall not be made until the original customer(s) or equivalent is actually connected to the extension. Refunds shall not include any amount of contribution in aid of construction for underground service made under the provisions of Rule C6.2, Underground Policy.

C. General

(1) Refundable deposits made with the Company under this rule shall be subject to refund without interest, for a five-year period which begins the month after the line extension is completed. The Company shall have no further obligation to refund any remaining portion of line extension deposits.

(2) Each extension shall be a separate, distinct unit and any further extension therefrom shall have no effect upon the agreements under which existing extensions were constructed.

(3) Refunds cannot exceed the refundable portion of the deposit

(4) Estimated construction costs shall exclude services and meters.

(5) The applicant shall furnish, without cost to the Company, all necessary rights-of-way and tree trimming permits, in a form satisfactory to the Company. If the applicant is unable to secure rights-of-way and permits, in a form satisfactory to the Company, the Company shall extend its distribution system along an alternate route selected by the Company, and shall require the applicant to pay all additional costs incurred.

(Continued on Sheet No. C-34.00)

(Continued From Sheet No. C-36.00)

C6. DISTRIBUTION SYSTEMS, LINE EXTENSIONS AND SERVICE CONNECTIONS (Contd)

C6.2 Underground Policy (Contd)

B. Installations of Underground Distribution Facilities - Residential (Contd)

Where a residential underground distribution system serves lots on one side of a street, the later connection of lots on the other side of the street to that existing system shall be considered as an original installation of a residential underground distribution system for such later-connected lots.

Streetlighting, if any, shall be served underground in areas served directly by residential underground distribution systems. The character and location of the streetlighting cables, if any, and all equipment constituting the residential underground distribution system, shall conform to specifications prepared by the Company.

Where the underground cable for a residential underground distribution system extends through areas within the subdivision which are undeveloped or consist of lots platted for future use and which are not to be served initially by the system, the front-foot measurement of both sides of the street or easement along which the cable extends through such areas shall be included in determining the contribution of the owner(s) or developer(s) for the residential underground distribution system.

Where the Company and the owner(s) or developer(s) agree that it is desirable to extend the underground cable to the boundary of a subdivision property from a point outside the subdivision a contribution of $7.00 per trench foot shall be required.

(b) Outside of subdivisions

The Company shall extend its Primary or Secondary distribution system from existing overhead or underground facilities. When any such extension is made from an existing overhead system the property owner may be required to provide an easement(s) for extension of the overhead system to a pole on his/her property where transition from overhead to underground can be made.

The customer shall be required to make a nonrefundable contribution in aid of construction to the Company, to cover the estimated total difference in cost between overhead and direct burial underground facilities for all underground facilities required to serve the customer.

(3) Installation of Underground Service Connections

The developer or customer shall be required to make a nonrefundable contribution in aid of construction to the Company, to cover the additional cost resulting from the installation of an underground service connection. For normal installations such contribution shall be computed on the basis of *a flat fee of $350.00 for the first 150 linear feet of service* from the termination of the Company's facilities at the front or rear property line to a point directly below the customer's meter. *Each additional foot of installation in excess of 150 linear feet shall be computed at $4.50 per linear foot.* Where special routing of the service lateral is required by the customer, the $4.50 per foot charge will apply to the route of the line as installed.

Where the electric service connection is installed jointly with the gas service line, the per foot charge for all footage, as measured, shall be reduced by 25 cents per foot.

(Continued on Sheet No. C-38.00)

(Continued From Sheet No. C-45.00)

C10. RENEWABLE ENERGY PLAN (REP) (Contd)

C10.2 Green Generation Program (Contd)

D. Customer Participation (Contd)

In the event the Green Generation Program is oversubscribed, the customer's name will be maintained on a Company list in the order under which they were received. The customer will be enrolled on a first-come, first-served basis for Green Generation Program Payment Options 1, 2 and 3. A customer electing Green Generation Program Payment Option 4 is subject to advance Company approval based on the availability of Green Generation Program Participation Certificates. Customers participating in Payment Options 1, 2 and 3 shall have priority for available Green Generation Program Participation Certificates. In all events, the Company reserves the right to reasonably prioritize customer participation based on economic, financial, operational, legal or other considerations.

A Green Generation Program participating customer relinquishes any rights to market or sell Green Tags or Renewable Energy Certificates (RECs) associated with the customer's participation in the Green Generation Program under this tariff. There is no provision to provide Green Tag certificates or RECs to participating customers under this tariff.

The Company may secure a third-party marketer to assist in marketing the Green Generation Program, soliciting customer and/or performing other functions on behalf of the Company. The contracted third-party marketer may contact the Company's customers directly. Under this condition, the Company would provide the contracted third-party marketer with limited customer information necessary for the sole purpose of promoting and administering the Green Generation Program on behalf of the Company. The Company will require any third-party marketer to hold customer information confidential and restrict its use to only that as authorized by the Company.

E. Payment Options and Pricing

Customers may participate in the Green Generation Program by voluntarily enrolling in a Green Generation Program payment option. In addition to the prices under the appropriate Rate Schedule, a customer who has agreed to participate in the Green Generation Program shall elect one of the following payment options:

Payment Option 1

Payment Option 1 allows customers to match 100% of their monthly total energy consumed with an equal amount of the renewable resource premium available under this program. Customers who elect to participate at the less than 15,000 kWh per month level shall pay a $0.01 per kWh renewable resource premium applicable to an amount equal to 100% of the customer's total monthly energy consumed.

Customers who elect to participate at the equal to or greater than 15,000 kWh per month level shall pay a $0.0085 per kWh renewable resource premium applicable to an amount equal to 100% of the customer's total monthly energy consumed. The minimum amount of the resource premium applicable is 15,000 kWh in any single billing month. *Customers desiring to aggregate energy consumed from multiple service accounts in order to participate at a level greater than 15,000 kWh shall be permitted to do so.*

After a customer elects to take service under Payment Option 1, the customer shall be permitted to change the established level of participation after 12 months have elapsed and 60 days notice has been given to the Company.

Payment Option 2

The customer may purchase Green Generation Program Participation Certificates in the amount of $1.50 per certificate per month. Each certificate shall represent 150 kWh of renewable electric energy procured by the Company in the Green Generation Program. Customers may purchase any number of Green Generation Program Certificates. In the event the amount of energy represented in the customer's Green Generation Program Participation Certificate exceeds the customer's actual kWh consumption for the billing period, no reconciliation shall be made on the customer's billing. If the amount of energy represented by the customer's selected Green Generation Program Participation Certificate exceeds the customer's actual kWh consumption for three consecutive billing periods, the customer may modify the number of Green Generation Program Participation Certificates selected.

(Continued on Sheet No. C-46.10)

SECTION D
RATE SCHEDULES

GENERAL TERMS AND CONDITIONS OF THE RATE SCHEDULES

A. Bills for utility service are subject to Michigan State Sales Tax. Customers may file a request with the Company for partial or total exemption from the application of sales tax in accordance with the laws of the State of Michigan and the rules of the Michigan State Department of Treasury.

B. Bills shall be increased within the limits of political subdivisions which levy special taxes, license fees or rentals against the Company's property, or its operation, or the production and/or sale of electric energy, to offset such special charges and thereby prevent other customers from being compelled to share such local increases.

C. Bills shall be increased to offset any new or increased specific tax or excise imposed by any governmental authority upon the Company's generation or sale of electrical energy.

D. A customer that commences service under any of the Company's Rate Schedules thereby agrees to abide by all of the applicable Rules and Regulations contained in this Rate Book for Electric Service.

E. Full Service Customers, applicants for service, or operators with generating facilities on or after June 8, 2012 are required to take service under *the Self-Generation Provision (SG) or* General Service Self Generation Rate GSG-2.

F. Full Service Customers shall not participate in any regional transmission organization wholesale market program until the Michigan Public Service Commission issues an order authorizing participation.

SURCHARGES

Rate Schedule	Renewable Energy Plan Surcharge (Case No U-17301) Effective beginning the July 2014 Bill Month[5]	Energy Efficiency Electric Program Surcharge (Case No. U-17351) Effective beginning the January 2014 Bill Month[3]	Energy Efficiency Self-Directed Customer Surcharge (Case No. U-17351) Effective beginning the January 2014 Bill Month[2]
Residential Rates	$0.00 /billing meter	$0.002830/kWh	NA
Rate GS and GSD [1]			
Tier 1: 0 – 1,250 kWh/mo.	$0.00 /billing meter	$ 1.63 /billing meter	$0.08 /billing meter
Tier 2: 1,251 – 5,000 kWh/mo.	0.00 /billing meter	8.89 /billing meter	0.42 /billing meter
Tier 3: 5,001 – 30,000 kWh/mo.	0.00 /billing meter	53.90 /billing meter	2.54 /billing meter
Tier 4: 30,001 – 50,000 kWh/mo.	0.00 /billing meter	53.90 /billing meter	2.54 /billing meter
Tier 5: > 50,000 kWh/mo.	0.00 /billing meter	53.90 /billing meter	2.54 /billing meter
Rate GP, GPD, GPTU and *EIP* [1]			
Tier 1: 0 – 5,000 kWh/mo.	$0.00 /billing meter	$ 3.38 /billing meter	$0.16 /billing meter
Tier 2: 5,001 – 10,000 kWh/mo.	0.00 /billing meter	24.86 /billing meter	1.18 /billing meter
Tier 3: 10,001 – 30,000 kWh/mo.	0.00 /billing meter	62.14 /billing meter	2.95 /billing meter
Tier 4: 30,001 – 50,000 kWh/mo.	0.00 /billing meter	149.06 /billing meter	7.04 /billing meter
Tier 5: > 50,000 kWh/mo.	0.00 /billing meter	714.18 /billing meter	31.88 /billing meter
Rate GSG-2	NA	NA[4]	NA
Rate GML[6]			
Tier 1: 0 – 1,250 kWh/mo.	$0.00 /billing meter	NA	NA
Tier 2: 1,251 – 5,000 kWh/mo.	0.00 /billing meter	NA	NA
Tier 3: >5,000 kWh/mo.	0.00 /billing meter	NA	NA
Rate GUL[6]	0.00 /luminaire	NA	NA
Rate GU-XL[6]	0.00 /luminaire	NA	NA
Rate GU			
Tier 1: 0 – 1,250 kWh/mo.	0.00 /billed account	NA	NA
Tier 2: 1,251 – 5,000 kWh/mo.	0.00 /billed account	NA	NA
Tier 3: >5,000 kWh/mo.	0.00 /billed account	NA	NA
Rate PA	NA	NA	NA
Rate ROA-R, ROA-S, ROA-P	NA	As in Delivery Rate Schedule	As in Delivery Rate Schedule

All Surcharges shall be applied on a monthly basis. The customer's consumption will be reviewed annually in the January bill month. Following the annual review, the customer may be subsequently moved to the Surcharge level for their applicable rate for the next billing period based on the customer's average consumption for the previous year. In situations where no historical consumption is available, the monthly Surcharge level will be based on the lowest consumption category for the secondary rate schedules or the lowest consumption category for primary rate schedules. No retroactive adjustment will be made due to the application of the REP or EE Surcharges associated with increases or decreases in consumption.

(1) Municipal Pumping customers shall be excluded from the Renewable Energy Plan Surcharge.

(2) An eligible customer who files and implements a self-directed plan in compliance with Rule C12 is required to pay the Energy Efficiency Self-Directed Program Surcharge.

(3) An Energy Efficiency Program Surcharge will be in effect for the period of the June 2009 Bill Month through the December 2015 Bill Month. The amount may vary during specific months as authorized by the Michigan Public Service Commission. Applicable cases include Case Nos. U-15805, U-16302, U-16303, U-16412, U-16670, U-16736, U-17281 and U-17351. The Surcharge for the period of the January 2014 Bill Month through the December 2014 Bill Month includes a financial incentive award approved by the Michigan Public Service Commission in Case No. U-17281. The Company will file a new tariff sheet to reflect the change in surcharges once the financial incentive recovery period has been completed.

(4) Rate GSG-2 Customers are eligible to opt-in to the Energy Efficiency Electric Program Surcharge for a two year pilot program beginning with the June 2012 bill month. A GSG-2 customer electing to participate in the Energy Efficiency Electric Program will be charged the GPD, Tier 5: > 50,000 kWh/mo rate of $714.18 per billing meter per month.

(5) The amount may vary during specific months as authorized by the Michigan Public Service Commission. Applicable cases include Case Nos. U-15805, U-16543, U-16581 and U-17301.

(6) Customer-Owned lighting fixtures served on Rate GML, GUL and Rate GU-XL are eligible to opt-in to the Energy Efficiency Program Surcharge. A GML, GUL or GU-XL customer electing to participate in the Energy Efficiency Electric Program will be charged the applicable surcharge as shown for Rate GS and GSD or Rate GP, GPD, GPTU and *EIP*, as applicable, per participating account per month.

M.P.S.C. No. 13 – Electric
Consumers Energy Company **Sheet No. D-3.00**

SURCHARGES

Rate Schedule	**Low-Income Energy Assistance Fund Surcharge (Case No. U-17377) Effective beginning with the September 2015 Bill Month**
Rate RS[(1)]	$0.98 /billing meter
Rate RT[(1)]	0.98 /billing meter
Rate REV-1[(1)]	0.98 /billing meter
Rate REV-2[(1)]	NA
Rate GS	0.98 /billing meter
Rate GSD	0.98 /billing meter
Rate GP	0.98 /billing meter
Rate GPD	0.98 /billing meter
Rate GPTU	0.98 /billing meter
Rate *EIP*	0.98 /billing meter
Rate GSG-2	0.98 /billing meter
Rate GML	0.98 /billing meter
Rate GUL	NA
Rate GU-XL	NA
Rate GU	NA
Rate PA	NA
Rate ROA-R	0.98 /billing meter
Rate ROA-S	0.98 /billing meter
Rate ROA-P	0.98 /billing meter

[(1)]The Low Income Energy Assistance Fund Surcharge, authorized by 2013 PA 295 and the July 23, 2015 Order in Case No. U-17377, shall be applied to one residential meter per residential site.

M.P.S.C. No. 13 – Electric
Consumers Energy Company **Sheet No. D-3.10**

SURCHARGES

Rate Schedule	***Jackson Gas Plant Purchase Surcharge (Case No. U-17735) Effective for service rendered on and after December 1, 2015***
Rate RS	*$(0.00121) /kWh*
Rate RT	*(0.00095) /kWh*
Rate REV-1	*(0.00121) /kWh*
Rate REV-2	*(0.00121) /kWh*
Rate RSDP	*(0.00121) /kWh*
Rate RSDPR	*(0.00121) /kWh*
Rate GS	*(0.00118) /kWh*
Rate GSDP	*(0.00118) /kWh*
Rate GSD	*(0.00112) /kWh*
Rate GSDDP	*(0.00112) /kWh*
Rate GP	*(0.00097) /kWh*
Rate GPDP	*(0.00097) /kWh*
Rate GPD	*(0.00084) /kWh*
Rate GPTU	*(0.00084) /kWh*
Rate EIP	*(0.00025) /kWh*
Rate GSG-2	*(0.00051) /kWh*
Rate GML	*NA*
Rate GUL	*NA*
Rate GU-XL	*NA*
Rate GU	*(0.00073) /kWh*
Rate PA	*NA*
Rate ROA-R	*NA*
Rate ROA-S	*NA*
Rate ROA-P	*NA*

POWER PLANT SECURITIZATION CHARGES

The actual Power Plant Securitization Charge is authorized pursuant to Rule C9.2, Power Plant Securitization Charges, Initial Implementation and True-up Methodology. The Power Plant Securitization Charge and the Power Plant Bill Credit are billed to all full service customers, shown in the rate schedules identified below, based upon usage. These charges shall be shown separately on the customer's bill.

The actual Power Plant Securitization Charge and Power Plant Bill Credit applied to customers' bills are as follows:

Rate Schedule	**Power Plant Securitization Charge (Case No. U-17473) Effective beginning with the August 2014 Billing Month**	**Power Plant Bill Credit (Case No. U-17473) Effective beginning with the August 2014 Billing Month**
Rate RS	$0.001187/kWh	$(0.001903)/kWh
Rate RT	0.001187/kWh	(0.001595)/kWh
Rate REV-1	0.001187/kWh	(0.001399)/kWh
Rate REV-2	0.001187/kWh	(0.001399)/kWh
Rate GS	0.001186/kWh	(0.002007)/kWh
Rate GSD	0.001186/kWh	(0.001875)/kWh
Rate GP		
CVL 1	0.000927/kWh	(0.001537)/kWh
CVL 2	0.000927/kWh	(0.001623)/kWh
CVL 3	0.000927/kWh	(0.001802)/kWh
Rates GPD, GPTU, *EIP* and GSG-2		
CVL 1	0.000927/kWh	(0.001326)/kWh
CVL 2	0.000927/kWh	(0.001447)/kWh
CVL 3	0.000927/kWh	(0.001664)/kWh
Rate GML	0.000566/kWh	(0.000924)/kWh
Rate GUL	0.000566/kWh	(0.000924)/kWh
Rate GU-XL	0.000566/kWh	(0.000924)/kWh
Rate GU	0.000566/kWh	(0.000924)/kWh
Rate PA	NA	NA
Rate ROA-R[1]	NA	NA
Rate ROA-S[1]	NA	NA
Rate ROA-P[1]	NA	NA

[1] 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 will pay the Power Plant Securitization Charges applicable to the customer's otherwise applicable Company Full Service Rate Schedule.

RATE CATEGORIES AND PROVISIONS

Description	Full Service	Retail Open Access
RESIDENTIAL SERVICE SECONDARY RATE RS		
Residential	1000	2000
Provisions		
Residential With Income Assistance (RIA) *	Applicable	Applicable
Residential With Senior Citizen (RSC) *	Applicable	Applicable
Residential With Direct Load Management (DLM)	1005	Not Applicable
Residential With Dynamic Pricing (RDP) **	1007	Not Applicable
Residential With Dynamic Pricing Rebate (RDPR) **	1008	Applicable
*Residential With Self-Generation (SG)** *	*1700*	*Not Applicable*
Net Metering Program	Applicable	Applicable
Green Generation Program	Applicable	Not Applicable
RESIDENTIAL SERVICE TIME-OF-DAY SECONDARY RATE RT		
Residential Time-of-Day	1010	2010
Provisions		
Residential Time-of-Day With Income Assistance (RIA) *	Applicable	Applicable
Residential Time-of-Day With Senior Citizen (RSC) *	Applicable	Applicable
*Residential Time-of-Day With Self-Generation (SG)*** *	*1705*	*Not Applicable*
Net Metering Program	Applicable	Not Applicable
Green Generation Program	Applicable	Not Applicable
EXPERIMENTAL RESIDENTIAL PLUG-IN ELECTRIC VEHICLE CHARGING PROGRAM		
Residential Electric Vehicle Service (REV-1)	1020	Not Applicable
*Residential Electric Vehicle Service (REV-1) With Self-Generation (SG)*** *	*1710*	*Not Applicable*
Residential Electric Vehicle Service (REV-2)	1030	Not Applicable
Green Generation	Applicable	Not Applicable

* Provisions shall not be taken in conjunction with each other.
** Provision shall not be taken in conjunction with the Direct Load Management Provision or Net Metering Program.
**** Provision shall not be taken in conjunction with the Net Metering Program.*

(Continued on Sheet No. D-6.10)

M.P.S.C. No. 13 - Electric
Consumers Energy Company **Sheet No. D-6.10**

RATE CATEGORIES AND PROVISIONS

(Continued From Sheet No. D-6.00)

Description	Full Service	Retail Open Access
GENERAL SERVICE SECONDARY RATE GS		
Commercial	1100	2100
Commercial – Temporary Construction Service	*1999*	*Not Applicable*
Industrial	1110	2110
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
Industrial With Educational Institution (GEI)	Applicable	Applicable
Commercial Direct Load Management DLM)	1118	Not Applicable
Industrial Direct Load Management (DLM)	1119	Not Applicable
Commercial With Dynamic Pricing*	1121	Not Applicable
Industrial With Dynamic Pricing*	1122	Not Applicable
*Commercial With Self-Generation (SG)***	*1715*	*Not Applicable*
*Industrial With Self-Generation (SG) ***	*1720*	*Not Applicable*
Net Metering Program	Applicable	Applicable
Green Generation Program	Applicable	Not Applicable
Non-Transmitting Meter Provision	Applicable	Applicable
GENERAL SERVICE SECONDARY DEMAND RATE GSD		
Commercial	1120	2120
Industrial	1130	2130
Commercial (100 kW Billing Demand Guarantee)	1140	2140
Industrial (100 kW Billing Demand Guarantee)	1150	2150
Provisions		
Commercial Resale	Applicable	Applicable
Commercial With Educational Institution (GEI)	Applicable	Applicable
Industrial With Educational Institution (GEI)	Applicable	Applicable
Commercial With Dynamic Pricing*	1156	Not Applicable
Industrial With Dynamic Pricing*	1157	Not Applicable
*Commercial With Self-Generation (SG)***	*1725*	*Not Applicable*
*Industrial With Self-Generation (SG) ***	*1730*	*Not Applicable*
*Commercial (100 kW Billing Demand Guarantee) With Self-Generation (SG)***	*1735*	*Not Applicable*
*Industrial (100 kW Billing Demand Guarantee) With Self-Generation (SG) ***	*1740*	*Not Applicable*
Net Metering Program	Applicable	Applicable
Green Generation Program	Applicable	Not Applicable
GENERAL SERVICE *PRIMARY* RATE GP		
Commercial (Customer Voltage Level 1, 2 or 3)	1200	2200
Industrial (Customer Voltage Level 1, 2 or 3)	1210	2210
Provisions		
Commercial (Customer Voltage Level 1, 2 or 3) Resale	Applicable	Applicable
Commercial (Customer Voltage Level 1, 2 or 3) With Educational Institution (GEI)	Applicable	Applicable
Commercial (Customer Voltage Level 1, 2 or 3) With Dynamic Pricing*	1211	Not Applicable
Industrial (Customer Voltage Level 1, 2 or 3) With Dynamic Pricing*	1212	Not Applicable
*Commercial With Self-Generation (SG)***	*1745*	*Not Applicable*
*Industrial With Self-Generation (SG) ***	*1750*	*Not Applicable*
Net Metering Program	Applicable	Applicable
Green Generation Program	Applicable	Not Applicable

* Provision shall not be taken in conjunction with the DLM Provision, GEI Provision, or the Net Metering Program.
*** Provision shall not be taken in conjunction with Dynamic Pricing or the Net Metering Program.*

(Continued on Sheet No. D-7.00)

RATE CATEGORIES AND PROVISIONS

(Continued From Sheet No. D-6.10)

Description	Full Service	Retail Open Access
GENERAL SERVICE *PRIMARY* DEMAND RATE GPD		
Commercial (Customer Voltage Level 1, 2 or 3)	1220	2220
Industrial (Customer Voltage Level 1, 2 or 3)	1230	2230
<u>Provisions</u>		
Commercial (Customer Voltage Level 1, 2 or 3) Resale	Applicable	Applicable
Industrial (Customer Voltage Level 1, 2 or 3) Resale	Applicable	Applicable
Commercial (Customer Voltage Level 1, 2 or 3) With Aggregate Peak Demand (GAP)**	Applicable	Applicable
Industrial (Customer Voltage Level 1, 2 or 3) With Aggregate Peak Demand (GAP)**	Applicable	Not Applicable
Commercial (Customer Voltage Level 1, 2 or 3) With Educational Institution (GEI)**	Applicable	Not Applicable
Industrial (Customer Voltage Level 1, 2 or 3) With Educational Institution (GEI)**	Applicable	Applicable
Commercial (Customer Voltage Level 1, 2 or 3) With Interruptible (GI)	Applicable	Applicable
Industrial (Customer Voltage Level 1, 2 or 3) With Interruptible (GI)	Applicable	Not Applicable
*Commercial (Customer Voltage Level 1, 2 or 3) With Self-Generation (SG)****	Applicable	Not Applicable
*Industrial (Customer Voltage Level 1, 2 or 3) With Self-Generation (SG)****	*1755*	*Not Applicable*
Net Metering Program	*1760*	*Not Applicable*
Green Generation Program	Applicable	Applicable
	Applicable	Not Applicable
GENERAL SERVICE PRIMARY TIME-OF-USE PILOT RATE GPTU		
Commercial (Customer Voltage Level 1, 2 or 3)	1280	Not Applicable
Industrial (Customer Voltage Level 1, 2 or 3)	1285	Not Applicable
<u>Provisions</u>		
*Commercial (Customer Voltage Level 1, 2 or 3) With Self-Generation (SG)****	*1765*	*Not Applicable*
*Industrial (Customer Voltage Level 1, 2 or 3) With Self-Generation (SG)****	*1770*	*Not Applicable*
Net Metering Program	Applicable	Not Applicable
Green Generation Program	Applicable	Not Applicable
GENERAL SERVICE *ENERGY INTENSIVE* PRIMARY RATE *EIP*		
Industrial (Customer Voltage Level 1, 2, or 3)	1250	Not Applicable

* Provisions shall not be taken in conjunction with the, DLM provision, GEI provision, or the Net Metering Program.
** Provisions shall not be taken in conjunction with each other.
**** Provision shall not be taken in conjunction with the DLM provision or the Net Metering Program.*

(Continued on Sheet No. D-7.10)

M.P.S.C. No. 13 - Electric
Consumers Energy Company **Sheet No. D-7.10**

RATE CATEGORIES AND PROVISIONS

(Continued From Sheet No. D-7.00)

Description	Full Service	Retail Open Access
EXPERIMENTAL ADVANCED RENEWABLE PROGRAM AR		
Residential	1015	2015
Commercial – Secondary Delivery, Rate GS	1105	2105
Industrial – Secondary Delivery, Rate GS	1115	2115
Commercial – Secondary Delivery, Rate GSD	1125	2125
Industrial – Secondary Delivery, Rate GSD	1135	2135
Commercial – Primary Delivery, Rate GP	1205	2205
Industrial – Primary Delivery, Rate GP	1215	2215
Commercial – Primary Delivery, Rate GPD	1225	2225
Industrial – Primary Delivery, Rate GPD	1235	2235
GENERAL SERVICE SELF GENERATION RATE GSG-2		
Commercial – Primary Service	1320	Not Applicable
Commercial (Customer Voltage Service Level 1, 2 or 3) – Primary Service 100 kW or less	1325	Not Applicable
Commercial (Customer Voltage Service Level 1, 2 or 3) – Primary Service over 100kW	1330	Not Applicable
Industrial – Primary Service	1340	Not Applicable
Industrial (Customer Voltage Service Level 1, 2 or 3) – Primary Service 100 kW or less	1345	Not Applicable
Industrial (Customer Voltage Service Level 1, 2 or 3) – Primary Service over 100kW	1350	Not Applicable
Provisions		
Green Generation Program	Applicable	Not Applicable

(Continued on Sheet No. D-8.10)

RATE CATEGORIES AND PROVISIONS

(Continued From Sheet No. D-7.10)

Description	Full Service	Retail Open Access
GENERAL SERVICE METERED LIGHTING RATE GML		
Commercial - Secondary Metered Service	1400	Not Applicable
Commercial - Primary Metered Service	1405	Not Applicable
Provisions		
Net Metering Program	Applicable	Applicable
Green Generation Program	Applicable	Not Applicable
GENERAL SERVICE UNMETERED LIGHTING RATE GUL		
Commercial - Customer-Owned Incandescent Luminaire	1410	Not Applicable
Commercial - Customer-Owned Mercury Vapor Luminaire	1415	Not Applicable
Commercial - Customer-Owned High-Pressure Sodium Luminaire	1420	Not Applicable
Commercial - Customer-Owned Metal Halide Luminaire	1425	Not Applicable
Commercial - Company-Owned Incandescent Luminaire	1430	Not Applicable
Commercial - Company-Owned Fluorescent Luminaire	1435	Not Applicable
Commercial - Company-Owned Mercury Vapor Luminaire	1440	Not Applicable
Commercial - Company-Owned High-Pressure Sodium Luminaire	1445	Not Applicable
Commercial - Company-Owned Metal Halide Luminaire	1450	Not Applicable
Commercial - Outdoor Area Lighting	1455	Not Applicable
Industrial - Outdoor Area Lighting	1460	Not Applicable
Provisions		
Green Generation Program	Applicable	Not Applicable
GENERAL UNMETERED EXPERIMENTAL LIGHTING RATE GU-XL		
Commercial - Company-Owned Secondary Service, XL	1600	Not Applicable
Commercial - Customer-Owned Secondary Service, XL	1650	Not Applicable
Provisions		
Green Generation Program	Applicable	Not Applicable
GENERAL SERVICE UNMETERED RATE GU		
Commercial - Secondary Service	1500	Not Applicable
Provisions		
Commercial - Lighting Service	Applicable	Not Applicable
Commercial - Traffic Lighting Service	Applicable	Not Applicable
Commercial - Cable Television (CATV) Service	Applicable	Not Applicable
Commercial - Wireless Access Service	Applicable	Not Applicable
Commercial - Security Camera Service	Applicable	Not Applicable
Green Generation Program	Applicable	Not Applicable
GENERAL SERVICE SPECIAL CONTRACTS		
Commercial	1150	Not Applicable

RESIDENTIAL SERVICE SECONDARY RATE RS

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 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:	$*0.092372*	per kWh for the first 600 kWh per month during the billing months of June-September
	$*0.133140*	per kWh for all kWh over 600 kWh per month during the billing months of June-September
	$*0.092372*	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-4.00.

Delivery Charges: These charges are applicable to Full Service and Retail Open Access customers.

System Access Charge:	$7.00	per customer per month
Distribution Charge:	$*0.045463*	per kWh for all kWh

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-3.10 and the Securitization Charges shown on Sheet Nos. D-5.00 and D-5.10.

(Continued on Sheet No. D-10.00)

RESIDENTIAL SERVICE SECONDARY RATE RS

(Continued From Sheet No. D-10.00)

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: $(3.50) per customer per month

This credit shall not be taken in conjunction with a credit for the Income Assistance Service Provision (RIA).

Self-Generation Provision (SG):

As of June 8, 2012, this provision may be required for any Full Service Customer with a generating installation less than 550 kW operating in parallel with the Company's system, which may employ cogeneration or small power production technology.

All facilities must meet the Parallel Operation Requirements set forth in Rule C1.6 B. The Company shall own, operate and maintain all metering and auxiliary devices (including telecommunication links) at the customer's expense. Meters furnished, installed and maintained by the Company shall meter generation equipment for customers that sell energy to the Company. No refund shall be made for any customer contribution required.

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) Secondary Voltage or Primary Voltage service. The Company will determine the particular nature of the voltage in each case.

Self-generation customers requiring Company delivery service for any portion of the load that has been self-generated will be charged as described in the Delivery Charges section of this Rate Schedule.

Sales of Self-Generated Energy to the Company:

A customer who meets the Federal Energy Regulatory Commission's (FERC) criteria for a Qualifying Facility may elect to sell energy to the Company. 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.

Where the customer elects to sell energy to the Company, an Interval Data Meter (IDM) or other applicable meter is required for their generator. 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.

Administrative Cost Charge: *$0.0010 per kWh purchased for generation installations with a capacity of 100 kW or less.*

Energy Purchase:

An energy purchase by the Company shall be bought at the Midwest Independent Transmission System Operator's (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) less $0.005/kWh. The Company may discontinue purchases during system emergencies, maintenance and other operational circumstances.

Direct Load Management Pilot (DLM):

A customer in a single family residence who is taking service from the Company may be eligible to participate in the Company's voluntary electric central air conditioning, central heat pump, or other qualifying electric equipment Load Management Pilot. Customer eligibility to participate in this pilot is determined solely by the Company.The customer must be located within an area in which Advanced Metering Infrastructure (AMI) is deployed and fully operational for purposes of this pilot. The Company will accept a customer's central air conditioning , central heat pump, and other qualifying electric equipment under this pilot 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 provision 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. 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.

(Continued on Sheet No. D-11.10)

RESIDENTIAL SERVICE SECONDARY RATE RS

(Continued From Sheet No. D-11.00)

Monthly Rate: (Contd)

Direct Load Management Pilot (DLM): (Contd)

The Company reserves the right to specify the term or duration of the pilot. The participating customer may elect to terminate service for any reason by providing the Company with thirty days' notice prior to the customer's next billing cycle. The customer's enrollment shall be terminated if the voluntary pilot 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 the regional grid operator.*

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 *Direct Load Management* 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 Direct Load Management Pilot.

The monthly **credit** for the Direct Load Management Pilot shall be applied as follows:

Power Supply Charges: These charges are applicable to Full Service Customers.

Direct Load Management Credit: $(*0.040768)* per kWh for all kWh over 600 kWh during the billing months of June-September

Residential Dynamic Pricing *Rate*:

The Dynamic Pricing is a voluntary *rate* available to Full Service residential customers taking service under the Company's RS tariff and who have, or are selected to have, the required metering equipment and infrastructure installed. Customer eligibility to participate in this *rate* is determined solely by the Company. The Company will furnish, install, maintain and own the required equipment at the customers' premises at the Company's expense. *At the sole discretion of the Company, customers may be allowed to furnish, install and maintain the equipment at the customer's expense.* Equipment *and* installations must conform to the Company's specifications. By enrolling in the *rate*, the customer agrees to participate in surveys and understands that the metering data will be used for evaluation purposes.

The participating customer may elect to terminate service for any reason giving the Company thirty days' notice prior to the customer's next billing cycle. The customer's enrollment shall be terminated if the *rate* ceases or for any reasons as provided for in Rule C1.3, Use of Service.

Deployment of the Residential Dynamic Pricing *Rate* is at the sole discretion of the Company and is dependent upon installation of advanced metering infrastructure and supporting critical systems.

This *rate* shall not be taken in conjunction with any other Demand Response Program or Net Metering.

The customer may choose either the Residential Dynamic Pricing or the Residential Dynamic Pricing Rebate.

(Continued on Sheet No. D-11.20)

RESIDENTIAL SERVICE SECONDARY RATE RS

(Continued From Sheet No. 11.10)

Monthly Rate: (Contd)

Residential Dynamic Pricing *Rate*: (Contd)

Residential Dynamic Pricing (RDP)

Customers placed under the RDP will be charged the power supply rates listed below in place of the standard RS tariff power supply rates for the summer months of June through September. Customers are able to manage electric costs by either reducing load during high cost pricing periods or shifting load from high cost pricing periods to lower cost pricing periods. The Company may select a subset of the RDP customers to be provided with additional technology at the Company's expense in order to measure the response difference between customers with and without the additional technology.

The Company may call up to eight critical peak events in the summer months of June through September, excluding weekends and holidays, for the on-peak hours of 2:00 PM to 6:00 PM. During a critical peak event, customers under the RDP will be charged the critical peak price in the place of the On-Peak power supply charge. Customers will be notified the day before a critical peak event is expected to occur. Receipt of such notice is the responsibility of the participating customer.

Power Supply Charges: These charges are applicable to Full Service Customers.

Summer Energy Charge

	$/kWh
Off-Peak	$*0.060368* for the hours of 12:00 AM to 7:00 AM and 11:00 PM to 12:00 AM
Mid-Peak	$*0.094707* for the hours of 7:00 AM to 2:00 PM and 6:00 PM to 11:00 PM
On-Peak	$*0.119736* for the hours of 2:00 PM to 6:00 PM
Critical Peak Pricing	$*0.950000* for the hours of 2:00 PM to 6:00 PM during a critical peak event day

Residential Critical Peak Rebate (RDPR)

Customers placed under the RDPR will be charged the power supply prices listed below in place of the standard RS tariff power supply rates for the summer months of June through September. Customers can manage their electric costs by either reducing load during the high cost pricing periods or shifting load from high cost pricing periods to lower cost pricing periods. The Company will provide a subset of the RDPR customers with additional technology at the Company's expense in order to measure the response difference between customers with and without the additional technology.

(Continued on Sheet No. D-11.30)

RESIDENTIAL SERVICE SECONDARY RATE RS

(Continued From Sheet No. D-11.20)

Monthly Rate: (Contd)

Residential Dynamic Pricing *Rate*: (Contd)

Residential Dynamic Pricing Rebate (RDPR) (Contd)

The Company may call up to eight critical peak events in the summer months of June through September, excluding weekends and holidays, for the on-peak hours of 2:00 PM to 6:00 PM. During a critical peak event, customers under the RDPR will be credited the critical peak rebate for incremental energy reductions . The customer's incremental energy reduction will be the difference between a customer's baseline hourly consumption and their recorded hourly consumption during a critical peak event. The customer's baseline consumption is the hourly average consumption from the prior five non-event business days. Customers will be notified the day before a critical peak event is expected to occur. Receipt of such notice is the responsibility of the participating customer.

Power Supply Charges: These charges are applicable to Full Service Customers.

Summer Energy Charge

		$/kWh
Off-Peak	$*0.072238*	for the hours of 12:00 AM to 7:00 AM and 11:00 PM to 12:00 AM
Mid-Peak	$*0.113329*	for the hours of 7:00 AM to 2:00 PM and 6:00 PM to 11:00 PM
On-Peak	$*0.143280*	for the hours of 2:00 PM to 6:00 PM
Critical Peak Pricing	$(*0.950000)*	for the hours of 2:00 PM to 6:00 PM during a critical peak event day

(Continued on Sheet No. D-12.00)

RESIDENTIAL SERVICE SECONDARY RATE RS

(Continued From Sheet No. D-11.30)

Monthly Rate: (Contd)

Net Metering Program:

The Net Metering Program is available to any eligible customer as described in Rule C11., 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.B, Net Metering Definitions.

A customer who participates in the Net Metering Program is subject to the provisions contained in Rule C11., 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.

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 applicable REP Surcharge and EE Surcharge shown on Sheet D-2.10, *the LIEAF Surcharge on Sheet D-3.00* and the System Access Charge included in the rate, adjusted for any service provision credit.

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 Gas Residential Service, R 460.122, Allowable Charges.

Term and Form of Contract:

Service under this rate shall not require a written contract except for the Green Generation Program participants.

M.P.S.C. No. 13 - Electric
Consumers Energy Company **Sheet No. D-13.10**

EXPERIMENTAL RESIDENTIAL PLUG-IN ELECTRIC VEHICLE CHARGING PROGRAM

Availability:

The Experimental Residential Plug-In Electric Vehicle Charging Program is a voluntary pilot available to Full Service residential customers. Upon enrollment of the customer in the program, the customer may take service under one of the following options as applicable:

Option 1 - Residential Home and Plug-in Electric Vehicle Time-of-Day Rate (REV-1) – Level 1 or Level 2 Charging of an electric vehicle combined with household electric usage such as space conditioning, cooking, water heating, refrigeration, clothes drying, incineration or lighting based upon on-peak, mid-peak and off-peak periods and through a single meter.

Option 2 - Residential Plug-In Electric Vehicle Only Time-of-Day Rate (REV-2) – Level 2 Charging of the electric vehicle based upon on-peak, mid-peak and off-peak periods through a separate meter. Electric usage for the household will be billed under the RS or RT Rate Schedule.

"Level 1 Charging" is defined as voltage connection of 120 volts and a maximum load of 12 amperes or 1.4 kVA.

"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.

"Electric Vehicle Supply Equipment (EVSE)" is defined as the conductors, including the ungrounded, grounded and equipment grounding conductors, the electric vehicle connectors, attachment plugs, and all other fittings, devices, power outlets, or apparatus installed specifically for the purpose of delivering energy from the premise wiring to the electric vehicle.

Vehicles shall be registered and operable on public highways in the State of Michigan to qualify for this rate. Low-speed electric vehicles including golf carts are not eligible to take service under this rate 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 program.

The total connected load of the home including the electric vehicle charging shall not exceed 10 kW, without the specific consent of the Company.

Customers shall not back-feed or transmit stored energy from the electric vehicle's battery to the Company's distribution system.

Subject to the limitation of this pilot program, the first 2,500 participating customers through December 31, 2014 may be reimbursed up to $2,500 toward the purchase of Company approved Electric Vehicle Supply Equipment (EVSE) if not otherwise provided, installation of the EVSE and a separately metered circuit as applicable. Installation must conform to Company specifications.

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.

Monthly Rate:

Option 1 REV-1:

Power Supply Charges: These charges are applicable to Full Service customers.

Energy Charge:

	$/kWh	
Off-Peak – Summer	$*0.060304*	per kWh for all Off-Peak kWh during the billing months of June-September
Mid-Peak – Summer	$*0.094700*	per kWh for all Mid-Peak kWh during the billing months of June-September
On-Peak – Summer	$*0.126371*	per kWh for all On-Peak kWh during the billing months of June-September
Off-Peak – Winter	$*0.060304*	per kWh for all Off-Peak kWh during the billing months of October-May
On-Peak – Winter	$*0.096350*	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-4.00.

(Continued on Sheet No. D-13.20)

EXPERIMENTAL RESIDENTIAL PLUG-IN ELECTRIC VEHICLE CHARGING PROGRAM
(Continued from Sheet No. D-13.10)

Monthly Rate (Continued):

Delivery Charges: These charges are applicable to Full Service customers.

System Access Charge:	$7.00	per customer per month
Distribution Charge:	$*0.045463*	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-3.10 and the Securitization Charges shown on Sheet Nos. D-5.00 and D-5.10.

General Terms:

These rates are subject to all general terms and conditions shown on Sheet No. D-1.00.

Self-Generation Provision (SG):

As of June 8, 2012, this provision may be required for any Full Service Customer with a generating installation less than 550 kW operating in parallel with the Company's system, which may employ cogeneration or small power production technology.

All facilities must meet the Parallel Operation Requirements set forth in Rule C1.6 B. The Company shall own, operate and maintain all metering and auxiliary devices (including telecommunication links) at the customer's expense. Meters furnished, installed and maintained by the Company shall meter generation equipment for customers that sell energy to the Company. No refund shall be made for any customer contribution required.

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) Secondary Voltage or Primary Voltage service. The Company will determine the particular nature of the voltage in each case.

Self-generation customers requiring Company delivery service for any portion of the load that has been self-generated will be charged as described in the Delivery Charges section of this Rate Schedule.

Sales of Self-Generated Energy to the Company:

A customer who meets the Federal Energy Regulatory Commission's (FERC) criteria for a Qualifying Facility may elect to sell energy to the Company. 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.

Where the customer elects to sell energy to the Company, an Interval Data Meter (IDM) or other applicable meter is required for their generator. 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.

Administrative Cost Charge: *$0.0010 per kWh purchased for generation installations with a capacity of 100 kW or less.*

Energy Purchase:

An energy purchase by the Company shall be bought at the Midwest Independent Transmission System Operator's (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) less $0.005/kWh. The Company may discontinue purchases during system emergencies, maintenance and other operational circumstance.

Option 2 – REV-2:

Power Supply Charges: These charges are applicable to Full Service customers.

Energy Charge:

	$/kWh
Off-Peak – Summer	$*0.060304* per kWh for all Off-Peak kWh during the billing months of June-September
Mid-Peak – Summer	$*0.094700* per kWh for all Mid-Peak kWh during the billing months of June-September
On-Peak – Summer	$*0.126371* per kWh for all On-Peak kWh during the billing months of June-September
Off-Peak – Winter	$*0.060304* per kWh for all Off-Peak kWh during the billing months of October-May

On-Peak – Winter $*0.096350* 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-4.00.

Delivery Charges: These charges are applicable to Full Service customers.

Distribution Charge: $*0.045463* for all kWh

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-3.10 and the Securitization Charges shown on Sheet Nos. D-5.00 and D-5.10. The REP Surcharge shown on Sheet No. D-2.10 shall not apply.

General Terms:

These rates are subject to all general terms and conditions shown on Sheet No. D-1.00.

(Continued on Sheet No. D-13.30)

RESIDENTIAL SERVICE TIME-OF-DAY SECONDARY RATE RT

Availability:

Subject to any restrictions, this rate is available to any residential customer desiring electric service who chooses to have their electric consumption metered based upon on-peak and off-peak periods. In addition, this rate is available to customers desiring electric service for electric vehicle battery charging where such service is in addition to all other household requirements. Battery charging service is limited to four-wheel vehicles licensed for operation on public streets and highways. 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.

Service under this rate is limited to 10,000 customers.

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.

On-Peak Energy Charge:	$*0.120663*	per kWh for all kWh during the billing months of June-September
Off-Peak Energy Charge:	$*0.075452*	per kWh for all kWh during the billing months of June-September
On-Peak Energy Charge:	$*0.095628*	per kWh for all kWh during the billing months of October-May
Off-Peak Energy Charge:	$*0.082554*	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-4.00.

Delivery Charges: These charges are applicable to Full Service and Retail Open Access Customers.

System Access Charge:	$7.00	per customer per month
Distribution Charge:	$*0.045463*	per kWh for all kWh

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-3.10 and the Securitization Charges shown on Sheet Nos. D-5.00 and D-5.10.

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 if the requirements under Rule B2, Consumer Standards and Billing Practices for Electric and Gas Residential Customers, R 460.102 are met. 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:	$(7.00)	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-15.00)

RESIDENTIAL SERVICE TIME-OF-DAY SECONDARY RATE RT

(Continued from Sheet No. D-14.00)

Monthly Rate: (Contd)

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 and Retail Open Access Customers.

Senior Citizen Credit: $(3.50) per customer per month

This credit shall not be taken in conjunction with a credit for the Income Assistance Service Provision (RIA).

Self-Generation Provision (SG):

As of June 8, 2012, this provision may be required for any Full Service Customer with a generating installation less than 550 kW operating in parallel with the Company's system, which may employ cogeneration or small power production technology.

All facilities must meet the Parallel Operation Requirements set forth in Rule C1.6 B. The Company shall own, operate and maintain all metering and auxiliary devices (including telecommunication links) at the customer's expense. Meters furnished, installed and maintained by the Company shall meter generation equipment for customers that sell energy to the Company. No refund shall be made for any customer contribution required.

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) Secondary Voltage or Primary Voltage service. The Company will determine the particular nature of the voltage in each case.

Self-generation customers requiring Company delivery service for any portion of the load that has been self-generated will be charged as described in the Delivery Charges section of this Rate Schedule.

Sales of Self-Generated Energy to the Company:

A customer who meets the Federal Energy Regulatory Commission's (FERC) criteria for a Qualifying Facility may elect to sell energy to the Company. 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.

Where the customer elects to sell energy to the Company, an Interval Data Meter (IDM) or other applicable meter is required for their generator. 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.

Administrative Cost Charge: *$0.0010 per kWh purchased for generation installations with a capacity of 100 kW or less.*

Energy Purchase:

An energy purchase by the Company shall be bought at the Midwest Independent Transmission System Operator's (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) less $0.005/kWh. The Company may discontinue purchases during system emergencies, maintenance and other operational circumstance.

(Continued on Sheet No. D-16.00)

RESIDENTIAL SERVICE TIME-OF-DAY SECONDARY RATE RT

(Continued from Sheet No. D-15.00)

Monthly Rate: (Contd)

Net Metering Program:

The Net Metering Program is available to any eligible customer as described in Rule C11., 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.B, Net Metering Definitions.

A customer who participates in the Net Metering Program is subject to the provisions contained in Rule C11, 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.

General Terms:

This rate is subject to all general terms and conditions shown on Sheet No. D-1.00.

Minimum Charge:

The applicable REP Surcharge and EE Surcharge shown on Sheet D-2.10*, the LIEAF Surcharge on Sheet D-3.00* and the System Access Charge included in the rate, adjusted for any service provision credit.

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 Gas Residential Service, R 460.122, Allowable Charges.

Schedule of On-Peak and Off-Peak Hours:

The following schedule shall apply Monday through Friday:

(1) On-Peak Hours: 11:00 AM to 7:00 PM
(2) Off-Peak Hours: 7:00 PM to 11:00 AM

Term and Form of Contract:

Service under this rate shall not require a written contract.

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) self-generation service, (v) resale for lighting service, or (vi) 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:	$0.100075	per kWh for all kWh-during the billing months of June-September
	$0.092496	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-4.00.

Delivery Charges: These charges are applicable to Full Service and Retail Open Access (ROA) Customers.

System Access Charge:	$20.00	per customer per month
Distribution Charge:	$0.042444	per kWh for all kWh

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-3.10 and the Securitization Charges shown on Sheet Nos. D-5.00 and D-5.10.

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-19.00)

GENERAL SERVICE SECONDARY RATE GS

(Continued From Sheet No. D-18.00)

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.

Educational Institution Credit: $*(0.000938)* 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 Provision (SG):

As of June 8, 2012, this provision may be required for any Full Service Customer with a generating installation less than 550 kW operating in parallel with the Company’s system, which may employ cogeneration or small power production technology.

All facilities must meet the Parallel Operation Requirements set forth in Rule C1.6 B. The Company shall own, operate and maintain all metering and auxiliary devices (including telecommunication links) at the customer's expense. Meters furnished, installed and maintained by the Company shall meter generation equipment for customers that sell energy to the Company. No refund shall be made for any customer contribution required.

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) Secondary Voltage or Primary Voltage service. The Company will determine the particular nature of the voltage in each case.

Self-generation customers requiring Company delivery service for any portion of the load that has been self-generated will be charged as described in the Delivery Charges section of this Rate Schedule.

Sales of Self-Generated Energy to the Company:

A customer who meets the Federal Energy Regulatory Commission’s (FERC) criteria for a Qualifying Facility may elect to sell energy to the Company. 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.

Where the customer elects to sell energy to the Company, an Interval Data Meter (IDM) or other applicable meter is required for their generator. 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.

Administrative Cost Charge: *$0.0010 per kWh purchased for generation installations with a capacity of 100 kW or less.*

Energy Purchase:

An energy purchase by the Company shall be bought at the Midwest Independent Transmission System Operator's (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) less $0.005/kWh. The Company may discontinue purchases during system emergencies, maintenance and other operational circumstances.

(Continued on Sheet No. D-19.10)

GENERAL SERVICE SECONDARY RATE GS

(Continued From Sheet No. D-19.00)

Monthly Rate: (Contd)

Direct Load Management Pilot (DLM):

A General Service Secondary Rate GS customer who is taking service from the Company may be eligible to participate in the Company's voluntary electric central air conditioning, central heat pump or other qualifying electric equipment Load Management Pilot. Customer eligibility to participate in this pilot is determined solely by the Company. The customer must be located within an area in which Advanced Metering Infrastructure (AMI) is deployed and fully operational for purposes of this provision. The Company will accept a customer's electric central air conditioning, central heat pump and other qualifying electric equipment under this pilot 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 provision only if the customer is allowing Load Management of their air conditioner or heat pump unit. This provision is not open to resale customers or customers taking the GEI or GMP provisions under Rate GS. The Company will install the required equipment at the customer's premises which will allow Load Management upon signal from the Company. Such equipment shall be furnished, installed, maintained and owned by the Company at the Company's expense. *At the sole discretion of the Company, customers may be allowed to furnish, install and maintain the equipment at the customer's expense.* Equipment *and* installations must conform to the Company's specifications.

The Company reserves the right to specify the term of duration of the pilot. The participating customer may elect to terminate service for any reason by providing the Company with thirty days' notice prior to the customer's next billing cycle. The customer's enrollment shall be terminated if the voluntary pilot ceases, if the customer tampers with the control switch or the Company's equipment or for 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 the regional grid operator.*

The customer may contact the Company 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 *Direct Load Management* 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 Direct Load Management Pilot.

The monthly **credit** for the Direct Load Management Pilot shall be applied as follows:

Power Supply Charges: These charges are applicable to Full Service Customers.

Direct Load Management Credit: $*(0.040768)* per kWh for all kWh over 1,200 kWh during the billing months of June-September

Dynamic Pricing Pilot:

The Dynamic Pricing Pilot is a voluntary pilot available at the discretion of the Company to Full Service Customers taking service under the Company's GS tariff and whom have, or are selected to have, the required metering equipment and infrastructure installed. Customer eligibility to participate in this pilot is determined solely by the Company. The Company will furnish, install, maintain and own the required equipment at the customers' premises at the Company's expense for the duration of the pilot. *At the sole discretion of the Company, customers may be allowed to furnish, install and maintain the equipment at the customer's expense.* Equipment *and* installations must conform to the Company's specifications. By enrolling in the pilot, the customer agrees to participate in surveys and understands that the metering data will be used for pilot evaluation purposes. This pilot shall not be taken in conjunction with the DLM Provision, the GEI Provision or Net Metering

(Continued on Sheet No. D-20.00)

GENERAL SERVICE SECONDARY RATE GS

(Continued from Sheet No. D-19.10)

Monthly Rate: (Contd)

Dynamic Pricing Pilot: (Contd)

The Company reserves the right to specify the term of duration of the pilot. The participating customer may elect to terminate service for any reason giving the Company thirty days' notice prior to the customer's next billing cycle. The customer's enrollment shall be terminated if the voluntary pilot ceases or for any reasons as provided for in Rule C1.3, Use of Service.

Deployment of the General Service Dynamic Pricing Pilot is at the sole discretion of the Company and is contingent upon installation of advanced metering infrastructure and supporting critical systems.

Customers that choose to participate in the Dynamic Pricing Pilot will be charged the power supply prices listed below in place of the standard GS tariff power supply rates for the summer months of June through September. Customers can manage their electric costs by either reducing load during high cost pricing periods or shifting load from high cost pricing periods to lower cost pricing periods. The Company may select a subset of the Dynamic Pricing Pilot customers to be provided with additional technology at the Company's expense in order to measure the response difference between customers with and without the additional technology.

The Company may call up to eight critical peak events in the summer months of June through September, excluding weekends and holidays, for the on-peak hours of 2:00 PM to 6:00 PM. During a critical peak event, customers will be charged the critical peak price in the place of the on-peak power supply charge. Customers will be notified the day before a critical peak event is expected to occur. Receipt of such notice is the responsibility of the participating customer.

Power Supply Charges: These charges are applicable to Full Service Customers.

Summer Energy Charge

	$/kWh	
Off-Peak	$*0.058861*	for the hours of 12:00 AM to 7:00 AM and 11:00 PM to 12:00 AM
Mid-Peak	$*0.092343*	for the hours of 7:00 AM to 2:00 PM and 6:00 PM to 11:00 PM
On-Peak	$*0.116747*	for the hours of 2:00 PM to 6:00 PM
Critical Peak Pricing	$*0.950000*	for the hours of 2:00 PM to 6:00 PM during a critical peak event day

Net Metering Program:

The Net Metering Program is available to any eligible customer as described in Rule C11., 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.B, Net Metering Definitions.

A customer who participates in the Net Metering Program is subject to the provisions contained in Rule C11., Net Metering Program.

(Continued on Sheet D-21.00)

GENERAL SERVICE SECONDARY RATE GS

(Continued from Sheet No. D-20.00)

Monthly Rate: (Contd)

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 applicable REP Surcharge and EE Surcharge shown on Sheet D-2.10*, the LIEAF Surcharge on Sheet D-3.00* and the System Access Charge included in the rate, adjusted for any service provision credit. 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 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) self-generation service, (iv) resale for lighting service, or (v) 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.

Capacity Charge:	$10.00	per kW for all kW of Peak Demand during the billing months of June-September
	$8.00	per kW for all kW of Peak Demand during the billing months of October-May
Energy Charge:	$*0.067573*	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: These charges are applicable to Full Service and Retail Open Access (ROA) customers.

System Access Charge:	$30.00	per customer per month
Capacity Charge:	$*1.15*	per kW for all kW of Peak Demand
Distribution Charge:	$*0.030067*	per kWh for all kWh

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-3.10 and the Securitization Charges shown on Sheet Nos. D-5.00 and D-5.10.

(Continued on Sheet No. D-23.00)

GENERAL SERVICE SECONDARY DEMAND RATE GSD

(Continued From Sheet No. D-23.00)

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.

Educational Institution Credit: $*(0.000769)* 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 Provision (SG):

Subject to any restrictions, as of June 8, 2012, this provision may be required for any Full Service Customer with a generating installation less than 550 kW operating in parallel with the Company’s system, which may employ cogeneration or small power production technology.

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 own, operate and maintain all metering and auxiliary devices (including telecommunication links) at the customer's expense. Meters furnished, installed and maintained by the Company shall meter generation equipment for customers that sell energy to the Company. No refund shall be made for any customer contribution required.

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) Secondary Voltage or Primary Voltage service. The Company will determine the particular nature of the voltage in each case.

Self-generation customers requiring Company delivery service for any portion of the load that has been self-generated will be charged as described in the Delivery Charges section of this Rate Schedule.

There shall be no double billing of demand under the base rate and the Self-Generation Provision.

Sales of Self-Generated Energy to the Company:

A customer who meets the Federal Energy Regulatory Commission’s (FERC) criteria for a Qualifying Facility may elect to sell energy to the Company. 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.

Where the customer elects to sell energy to the Company, an Interval Data Meter (IDM) or other applicable meter is required for their generator. 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.

Administrative Cost Charge: *$0.0010 per kWh purchased for generation installations with a capacity of 100 kW or less.*

Energy Purchase:

An energy purchase by the Company shall be bought at the Midwest Independent Transmission System Operator's (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) less $0.005/kWh. The Company may discontinue purchases during system emergencies, maintenance and other operational circumstances.

Dynamic Pricing Pilot:

The Dynamic Pricing Pilot is a voluntary pilot available at the discretion of the Company to Full Service Customers taking service under the Company's GSD tariff and whom have, or are selected to have, the required metering equipment and infrastructure installed. Customer eligibility to participate in this pilot is determined solely by the Company. The Company will furnish, install, maintain and own the required equipment at the customers' premises at the Company's expense for the duration of the pilot. *At the sole discretion of the Company, customers may be allowed to furnish, install and maintain the equipment at the customer's expense.* Equipment *and* installations must conform to the Company's specifications. By enrolling in the pilot, the customer agrees to participate in surveys and understands that the metering data will be used for pilot evaluation purposes. This pilot shall not be taken in conjunction with the GEI Provision or Net Metering.

The Company reserves the right to specify the term of duration of the pilot. The participating customer may elect to terminate service for any reason giving the Company thirty days' notice prior to the customer's next billing cycle. The customer's enrollment shall be terminated if the voluntary pilot ceases or for any reasons as provided for in Rule C1.3, Use of Service.

Deployment of the General Service Dynamic Pricing Pilot is at the sole discretion of the Company and is contingent upon installation of advanced metering infrastructure and supporting critical systems.

Customers that choose to participate in the Dynamic Pricing Pilot will be charged the power supply prices listed below in place of the standard GSD tariff power supply rates for the summer months of June through September. Customers can manage their electric costs by either reducing load during high cost pricing periods or shifting load from high cost pricing periods to lower cost pricing periods. The Company may select a subset of the Dynamic Pricing customers to be provided with additional technology at the Company's expense in order to measure the response difference between customers with and without the additional technology.

(Continued on Sheet No. D-25.00)

GENERAL SERVICE SECONDARY DEMAND RATE GSD

(Continued From Sheet No. D-24.00)

Monthly Rate: (Contd)

Dynamic Pricing Pilot: (Contd)

The Company may call up to eight critical peak events in the summer months of June through September, excluding weekends and holidays, for the on-peak hours of 2:00 PM to 6:00 PM. During a critical peak event, customers will be charged the critical peak price in the place of the on-peak power supply charge. Customers will be notified the day before a critical peak event is expected to occur. Receipt of such notice is the responsibility of the participating customer.

Power Supply Charges: These charges are applicable to Full Service Customers.

Summer Energy Charge

Capacity Charge	$10.00	per kW for all kW of Peak Demand during the billing months of June through September
Off-Peak	$*0.035018*	per kWh for the hours of 12:00 AM to 7:00 AM and 11:00 PM to 12:00 AM
Mid-Peak	$*0.063760*	per kWh for the hours of 7:00 AM to 2:00 PM and 6:00 PM to 11:00 PM
On-Peak	$*0.081314*	per kWh for the hours of 2:00 PM to 6:00 PM
Critical Peak Pricing	$*0.950000*	per kWh for the hours of 2:00 PM to 6:00 PM during a critical peak event day

Net Metering Program:

The Net Metering Program is available to any eligible customer as described in Rule C11., 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.B, Net Metering Definitions.

A customer who participates in the Net Metering Program is subject to the provisions contained in Rule C11., 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.

General Terms:

This rate is subject to all general terms and conditions shown on Sheet No. D-1.00.

Minimum Charge:

The applicable REP Surcharge and EE Surcharge shown on Sheet D-2.10, *the LIEAF Surcharge on Sheet D-3.00* and capacity charges and the System Access Charge included in the rate.

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 .

(Continued on Sheet No. D-26.00)

GENERAL SERVICE SECONDARY DEMAND RATE GSD

(Continued From Sheet No. D-25.00)

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:

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 (CVL 3)

Energy Charge:	$*0.094730*	per kWh for all kWh during the billing months of June-September
	$*0.088010*	per kWh for all kWh during the billing months of October-May

Charges for Customer Voltage Level 2 (CVL 2)

Energy Charge	$*0.093799*	per kWh for all kWh during the billing months of June-September
	$*0.087079*	per kWh for all kWh during the billing months of October-May

Charges for Customer Voltage Level 1 (CVL 1)

Energy Charge	$*0.088723*	per kWh for all kWh during the billing months of June-September
	$*0.082003*	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-4.00.

(Continued on Sheet No. D-27.10)

M.P.S.C. No. 13 - Electric
Consumers Energy Company **Sheet No. D-27.10**

GENERAL SERVICE PRIMARY RATE GP

(Continued From Sheet No. D-27-00)

Monthly Rate: (Contd)

Delivery Charges: These charges are applicable to Full Service and Retail Open Access (ROA) Customers.

System Access Charge: $50.00 per customer per month

Charges for Customer Voltage Level 3 (CVL 3)

Distribution Charge: $*0.017766* per kWh for all kWh

Charges for Customer Voltage Level 2 (CVL 2)

Distribution Charge: $*0.010974* per kWh for all kWh

Charges for Customer Voltage Level 1 (CVL 1)

Distribution Charge: $*0.008185* per kWh for all kWh

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-3.10 and the Securitization Charges shown on Sheet Nos. D-5.00 and D-5.10.

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, 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.

Substation Ownership Credit: $*(0.000409)* 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 Maximum Demand on each substation 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.

(Continued on Sheet No. D-28.00)

GENERAL SERVICE PRIMARY RATE GP

(Continued From Sheet No. D-27-10)

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.

Educational Institution Credit: $*(0.000656)* 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 Provision (SG):

As of June 8, 2012, this provision may be required for any Full Service Customer with a generating installation less than 550 kW operating in parallel with the Company's system, which may employ cogeneration or small power production technology.

All facilities must meet the Parallel Operation Requirements set forth in Rule C1.6 B. The Company shall own, operate and maintain all metering and auxiliary devices (including telecommunication links) at the customer's expense. Meters furnished, installed and maintained by the Company shall meter generation equipment for customers that sell energy to the Company. No refund shall be made for any customer contribution required.

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) Secondary Voltage or Primary Voltage service. The Company will determine the particular nature of the voltage in each case.

Self-generation customers requiring Company delivery service for any portion of the load that has been self-generated will be charged as described in the Delivery Charges section of this Rate Schedule.

Sales of Self-Generated Energy to the Company:

A customer who meets the Federal Energy Regulatory Commission's (FERC) criteria for a Qualifying Facility may elect to sell energy to the Company. 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.

Where the customer elects to sell energy to the Company, an Interval Data Meter (IDM) or other applicable meter is required for their generator. 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.

Administrative Cost Charge: *$0.0010 per kWh purchased for generation installations with a capacity of 100 kW or less.*

Energy Purchase:

An energy purchase by the Company shall be bought at the Midwest Independent Transmission System Operator's (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) less $0.005/kWh. The Company may discontinue purchases during system emergencies, maintenance and other operational circumstances.

(Continued on Sheet No. D-29. 00)

GENERAL SERVICE PRIMARY RATE GP

(Continued From Sheet No. D-28.00)

Monthly Rate: (Contd)

Dynamic Pricing Pilot

The Dynamic Pricing Pilot is a voluntary pilot available at the discretion of the Company to Full Service Customers taking service under the Company's GP tariff and whom have, or are selected to 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 for the duration of the pilot. *At the sole discretion of the Company, customers may be allowed to furnish, install and maintain the equipment at the customer's expense.* Equipment *and* installations must conform to the Company's specifications. By enrolling in the pilot, the customer agrees to participate in surveys and understands that the metering data will be used for pilot evaluation purposes. This pilot shall not be taken in conjunction with the GEI Provision or Net Metering.

The Company reserves the right to specify the term of duration of the pilot. The participating customer may elect to terminate service for any reason giving the Company thirty days' notice prior to the customer's next billing cycle. The customer's enrollment shall be terminated if the voluntary pilot ceases or for any reasons as provided for in Rule C1.3, Use of Service.

Customers that choose to participate in the Dynamic Pricing Pilot will be charged the power supply prices listed below in place of the standard GP tariff power supply rates for the summer months of June through September. Customers can manage their electric costs by either reducing load during high cost pricing periods or shifting load from high cost pricing periods to lower cost pricing periods. The Company may select a subset of the Dynamic Pricing customers to be provided with additional technology at the Company's expense in order to measure the response difference between customers with and without the additional technology.

Deployment of the General Service Dynamic Pricing Pilot is at the sole discretion of the Company and is contingent upon installation of advanced metering infrastructure and supporting critical systems.

The Company may call up to eight critical peak events in the summer months of June through September, excluding weekends and holidays, for the on-peak hours of 2:00 PM to 6:00 PM. During a critical peak event, customers will be charged the critical peak price in the place of the On-Peak power supply charge. Customers will be notified the day before a critical peak event is expected to occur. Receipt of such notice is the responsibility of the participating customer.

Power Supply Charges: These charges are applicable to Full Service Customers.

Summer Energy Charge for Customer Voltage Level 3 (CVL 3)

	$/kWh	
Off-Peak	$*0.055679*	for the hours of 12:00 AM to 7:00 AM and 11:00 PM to 12:00 AM
Mid-Peak	$*0.093569*	for the hours of 7:00 AM to 2:00 PM and 6:00 PM to 11:00 PM
On-Peak	$*0.122852*	for the hours of 2:00 PM to 6:00 PM
Critical Peak Pricing	$*0.800000*	for the hours of 2:00 PM to 6:00 PM during a critical peak event day

Summer Energy Charge for Customer Voltage Level 2 (CVL 2)

	$/kWh	
Off-Peak	$*0.054748*	for the hours of 12:00 AM to 7:00 AM and 11:00 PM to 12:00 AM
Mid-Peak	$*0.092638*	for the hours of 7:00 AM to 2:00 PM and 6:00 PM to 11:00 PM
On-Peak	$*0.121921*	for the hours of 2:00 PM to 6:00 PM
Critical Peak Pricing	$*0.799069*	for the hours of 2:00 PM to 6:00 PM during a critical peak event day

(Continued on Sheet No. D-29.10)

GENERAL SERVICE PRIMARY RATE GP

(Continued From Sheet No. D-29.00)

Monthly Rate: (Contd)

Dynamic Pricing Pilot (Contd)

Summer Energy Charge for Customer Voltage Level 1 (CVL 1)

	$/kWh	
Off-Peak	$*0.049672*	for the hours of 12:00 AM to 7:00 AM and 11:00 PM to 12:00 AM
Mid-Peak	$*0.087562*	for the hours of 7:00 AM to 2:00 PM and 6:00 PM to 11:00 PM
On-Peak	$*0.116845*	for the hours of 2:00 PM to 6:00 PM
Critical Peak Pricing	$*0.793993*	for the hours of 2:00 PM to 6:00 PM during a critical peak event day

Net Metering Program:

The Net Metering Program is available to any eligible customer as described in Rule C11., 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.B, Net Metering Definitions.

A customer who participates in the Net Metering Program is subject to the provisions contained in Rule C11., 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.

General Terms:

This rate is subject to all general terms and conditions shown on Sheet No. D-1.00.

Minimum Charge:

The applicable REP Surcharge and EE Surcharge shown on Sheet D-2.10*, the LIEAF Surcharge on Sheet D-3.00* and capacity charges and the System Access Charge included in the rate.

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.

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 self-generation 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 (CVL 3)

Capacity Charge:	$*21.42*	per kW of On-Peak Billing Demand during the billing months of June-September
	$*18.42*	per kW of On-Peak Billing Demand during the billing months of October-May
Energy Charge:	$*0.054493*	per kWh for all On-Peak kWh during the billing months of June-September
	$*0.037615*	per kWh for all Off-Peak kWh during the billing months of June-September
	$*0.046546*	per kWh for all On-Peak kWh during the billing months of October-May
	$*0.040759*	per kWh for all Off-Peak kWh during the billing months of October-May

Charges for Customer Voltage Level 2 (CVL 2)

Capacity Charge:	$*20.42*	per kW of On-Peak Billing Demand during the billing months of June-September
	$*17.42*	per kW of On-Peak Billing Demand during the billing months of October-May
Energy Charge:	$*0.053562*	per kWh for all On-Peak kWh during the billing months of June-September
	$*0.036684*	per kWh for all Off-Peak kWh during the billing months of June-September
	$*0.045615*	per kWh for all On-Peak kWh during the billing months of October-May
	$*0.039828*	per kWh for all Off-Peak kWh during the billing months of October-May

(Continued on Sheet No. D-31.10)

GENERAL SERVICE PRIMARY DEMAND RATE GPD

(Continued From Sheet No. D-31.00)

Monthly Rate: (Contd)

Power Supply Charges: These charges are applicable to Full Service Customers. (Contd)

Charges for Customer Voltage Level 1 (CVL 1)

Capacity Charge:	$*19.42*	per kW of On-Peak Billing Demand during the billing months of June-September
	$*16.42*	per kW of On-Peak Billing Demand during the billing months of October-May
Energy Charge:	$*0.048486*	per kWh for all On-Peak kWh during the billing months of June-September
	$*0.031608*	per kWh for all Off-Peak kWh during the billing months of June-September
	$*0.040539*	per kWh for all On-Peak kWh during the billing months of October-May
	$*0.034752*	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-4.00.

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 (CVL 3)

Capacity Charge: $*4.10* per kW of Maximum Demand

Charges for Customer Voltage Level 2 (CVL 2)

Capacity Charge: $*2.29* per kW of Maximum Demand

Charges for Customer Voltage Level 1 (CVL 1)

Capacity Charge: $*0.67* per kW of Maximum Demand

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-3.10 and the Securitization Charges shown on Sheet Nos. D-5.00 and D-5.10.

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 *0.850 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.

(Continued on Sheet No. D-32.00)

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 billing month, but never 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.

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.**

Substation Ownership Credit:	$(0.30)	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 Maximum Demand on each substation 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.

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.

(Continued on Sheet No. D-32.00)

GENERAL SERVICE PRIMARY DEMAND RATE GPD

(Continued From Sheet No. D-33.00)

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.**

Educational Institution Credit:

$*(0.000337)* 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-34.10)

GENERAL SERVICE PRIMARY DEMAND RATE GPD

(Continued From Sheet No. D-34.00)

Monthly Rate: (Contd)

Self-Generation Provision (SG):

Subject to any restrictions, as of June 8, 2012, this provision may be required for any Full Service Customer with a generating installation less than 550 kW operating in parallel with the Company's system, which may employ cogeneration or small power production technology.

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 own, operate and maintain all metering and auxiliary devices (including telecommunication links) at the customer's expense. Meters furnished, installed and maintained by the Company shall meter generation equipment for customers that sell energy to the Company. No refund shall be made for any customer contribution required.

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) Secondary Voltage or Primary Voltage service. The Company will determine the particular nature of the voltage in each case.

Self-generation customers requiring Company delivery service for any portion of the load that has been self-generated will be charged as described in the Delivery Charges section of this Rate Schedule.

There shall be no double billing of demand under the base rate and the Self-Generation Provision.

Sales of Self-Generated Energy to the Company:

A customer who meets the Federal Energy Regulatory Commission's (FERC) criteria for a Qualifying Facility may elect to sell energy to the Company. 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.

Where the customer elects to sell energy to the Company, an Interval Data Meter (IDM) or other applicable meter is required for their generator. 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.

Administrative Cost Charge: *$0.0010 per kWh purchased for generation installations with a capacity of 100 kW or less.*

Energy Purchase:

An energy purchase by the Company shall be bought at the Midwest Independent Transmission System Operator's (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) less $0.005/kWh. The Company may discontinue purchases during system emergencies, maintenance and other operational circumstances.

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 50,000 kW. The aggregate amount of monthly On-Peak Billing Demand subscribed under this provision shall be limited to 250,000 kW.

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.

(Continued on Sheet No. D-35.00)

GENERAL SERVICE PRIMARY DEMAND RATE GPD

(Continued From Sheet No. D-34.10)

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. Within 10 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.

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 Midwest Independent Transmission System Operator (MISO) requirements as determined by the Company and 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.

<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 endeavor to provide notice in advance of probable interruption, and if possible, a second notice of positive interruption. However, this service shall be interrupted immediately upon notice should the Company deem such action necessary. 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 $50.00 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
	$(4.00)	per kW of On-Peak Billing Demand during the billing months of October-May

(Continued of Sheet No. D-36.00)

GENERAL SERVICE PRIMARY DEMAND RATE GPD

(Continued From Sheet No. D-35.00)

Monthly Rate: (Contd)

Net Metering Program:

The Net Metering Program is available to any eligible customer as described in Rule C11., 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.B, Net Metering Definitions.

A customer who participates in the Net Metering Program is subject to the provisions contained in Rule C11., 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.

General Terms:

This rate is subject to all general terms and conditions shown on Sheet No. D-1.00.

Minimum Charge:

The applicable REP Surcharge and EE Surcharge shown on Sheet D-2.10*, the LIEAF Surcharge on Sheet D-3.00* and capacity charges and the System Access Charge included in the rate.

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 Resale Service Provision, (ii) service under the Green Generation Program, (iii) service under the Educational Institution Service Provision, (iv) service under the Aggregate Peak Demand Service Provision, (v) service under the Interruptible 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.

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.

GENERAL SERVICE PRIMARY TIME-OF-USE PILOT RATE GPTU

Availability:

Subject to any restrictions, this experimental General Service Primary Time-Of-Use (GPTU) Pilot Rate is available to any Full Service Customer with a Maximum Demand of 5 MW or less taking service at the Company's Primary Voltage level. This rate is limited to *100 MW* of Maximum Demand capacity.

If the capacity of all customers requesting service in writing under this rate exceeds *100 MW* of Maximum Demand capacity to be served on Pilot rate GPTU will be awarded based on a *first-come, first-served basis after receipt of the MPSC Order approving the 100 MW limit*.
This pilot rate is effective for bills rendered during the billing month which begins a minimum of thirty days after issuance of the final Order in Case No. U-17087 and remains in effect for five years.

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-36.20)

GENERAL SERVICE PRIMARY TIME-OF-USE PILOT RATE GPTU

(Continued from Sheet No. D-36.10)

Monthly Rate:

Power Supply Charges:

Charges for Customer Voltage Level 3 (CVL 3)

Energy Charge:

Off-Peak - Summer	$*0.056767*	per kWh during the calendar months of June - September
Low-Peak - Summer	$*0.073939*	per kWh during the calendar months of June - September
Mid-Peak - Summer	$*0.100475*	per kWh during the calendar months of June - September
High-Peak - Summer	$*0.123764*	per kWh during the calendar months of June - September
Off-Peak - Winter	$*0.072965*	per kWh during the calendar months of October - May
Mid-Peak - Winter	$*0.087803*	per kWh during the calendar months of October - May
High-Peak - Winter	$*0.092608*	per kWh during the calendar months of October - May

Charges for Customer Voltage Level 2 (CVL 2)

Energy Charge:

Off-Peak - Summer	$*0.055836*	per kWh during the calendar months of June - September
Low-Peak - Summer	$*0.073008*	per kWh during the calendar months of June - September
Mid-Peak - Summer	$*0.099544*	per kWh during the calendar months of June - September
High-Peak - Summer	$*0.122833*	per kWh during the calendar months of June - September
Off-Peak - Winter	$*0.072034*	per kWh during the calendar months of October - May
Mid-Peak - Winter	$*0.086872*	per kWh during the calendar months of October - May
High-Peak - Winter	$*0.091677*	per kWh during the calendar months of October - May

Charges for Customer Voltage Level 1 (CVL 1)

Energy Charge:

Off-Peak - Summer	$*0.050760*	per kWh during the calendar months of June - September
Low-Peak - Summer	$*0.067932*	per kWh during the calendar months of June - September
Mid-Peak - Summer	$*0.094468*	per kWh during the calendar months of June - September
High-Peak - Summer	$*0.117757*	per kWh during the calendar months of June - September
Off-Peak - Winter	$*0.066958*	per kWh during the calendar months of October - May
Mid-Peak - Winter	$*0.081796*	per kWh during the calendar months of October - May
High-Peak - Winter	$*0.086601*	per kWh during the calendar months of October - May

Delivery Charges:

System Access Charge: $100.00 per customer 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: $*2.29* per kW of Maximum Demand

Charges for Customer Voltage Level 1 (CVL 1)

Capacity Charge: $*0.67* per kW of Maximum Demand

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-3.10 and the Securitization Charges shown on Sheet Nos. D-5.00 and D-5.10.

(Continue on Sheet No. D-36.30)

GENERAL SERVICE PRIMARY TIME-OF-USE PILOT RATE GPTU

(Continued from Sheet No. D-36.20)

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 *0.850 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 Customers.

Substation Ownership Credit: $(0.30) 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 Maximum Demand on each substation 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 Provision (SG):

Subject to any restrictions, as of June 8, 2012, this provision may be required for any Full Service Customer with a generating installation less than 550 kW operating in parallel with the Company's system, which may employ cogeneration or small power production technology.

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 own, operate and maintain all metering and auxiliary devices (including telecommunication links) at the customer's expense. Meters furnished, installed and maintained by the Company shall meter generation equipment for customers that sell energy to the Company. No refund shall be made for any customer contribution required.

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) Secondary Voltage or Primary Voltage service. The Company will determine the particular nature of the voltage in each case.

Self-generation customers requiring Company delivery service for any portion of the load that has been self-generated will be charged as described in the Delivery Charges section of this Rate Schedule.

There shall be no double billing of demand under the base rate and the Self-Generation Provision.

Sales of Self-Generated Energy to the Company:

A customer who meets the Federal Energy Regulatory Commission's (FERC) criteria for a Qualifying Facility may elect to sell energy to the Company. 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.

Where the customer elects to sell energy to the Company, an Interval Data Meter (IDM) or other applicable meter is required for their generator. 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.

Administrative Cost Charge:

$0.0010 per kWh purchased for generation installations with a capacity of 100 kW or less.

Energy Purchase:

An energy purchase by the Company shall be bought at the Midwest Independent Transmission System Operator's (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) less $0.005/kWh. The Company may discontinue purchases during system emergencies, maintenance and other operational circumstances.

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 applicable REP Surcharge and EE Surcharge shown on Sheet D-2.10, *the LIEAF Surcharge on Sheet D-3.00* and capacity charges and the System Access Charge included in the rate.

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.

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*. This rate is limited to existing metal melting customers taking service under the Company's Furnace/Metal Melting Service Provision (GFM), on June 7, 2012, the date of the final order in Case No. U-16794. 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 and have an annual load factor that exceeds 70%.* New electric metal melting *or energy intensive* 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 (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-37.10)

ENERGY INTENSIVE PRIMARY RATE *EIP*

(Continued from Sheet No. D-37.00)

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:	3:00 PM to 5:00 PM 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:	5:00 PM to 7:00 PM 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 (CVL 3)

Energy Charge:

Off-Peak – Summer	$*0.041451*	per kWh during the calendar months of June - September
Low-Peak - Summer	$*0.066938*	per kWh during the calendar months of June - September
Mid-Peak - Summer	$*0.081292*	per kWh during the calendar months of June - September
High-Peak - Summer	$*0.093423*	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	$*0.062688*	per kWh during the calendar months of October - May
Mid-Peak - Winter	$*0.070705*	per kWh during the calendar months of October - May
High-Peak- Winter	$*0.071993*	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-37.20)

ENERGY INTENSIVE PRIMARY RATE *EIP*

(Continued from Sheet No. D-37.10)

Power Supply Charges: (Contd)

Charges for Customer Voltage Level 2 (CVL 2)

Energy Charge:

Off-Peak - Summer	$*0.040520*	per kWh during the calendar months of June - September
Low-Peak - Summer	$*0.066007*	per kWh during the calendar months of June - September
Mid-Peak - Summer	$*0.080361*	per kWh during the calendar months of June - September
High-Peak - Summer	$*0.092492*	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	$*0.061757*	per kWh during the calendar months of October - May
Mid-Peak - Winter	$*0.069774*	per kWh during the calendar months of October - May
High-Peak- Winter	$*0.071062*	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 (CVL 1)

Energy Charge:

Off-Peak - Summer	$*0.035444*	per kWh during the calendar months of June - September
Low-Peak - Summer	$*0.060931*	per kWh during the calendar months of June - September
Mid-Peak - Summer	$*0.075285*	per kWh during the calendar months of June - September
High-Peak - Summer	$*0.087416*	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	$*0.056681*	per kWh during the calendar months of October - May
Mid-Peak - Winter	$*0.064698*	per kWh during the calendar months of October - May
High-Peak- Winter	$*0.065986*	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

Delivery Charges:

System Access Charge: $100.00 per customer per month

Charges for Customer Voltage Level 3 (CVL 3):

Capacity Charge:	$1.00	per kW of Maximum Demand
Distribution Charge:	$*0.011576*	per kWh for all kWh for a Full Service Customer

Charges for Customer Voltage Level 2 (CVL 2):

Capacity Charge:	$0.50	per kW of Maximum Demand
Distribution Charge:	$*0.004784*	per kWh for all kWh for a Full Service Customer

Charges for Customer Voltage Level 1 (CVL 1):

Capacity Charge:	$0.30	per kW of Maximum Demand
Distribution Charge:	$*0.001995*	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-3.10 and the Securitization Charges shown on Sheet Nos. D-5.00 and D-5.10.

(Continued on Sheet No. D-37.30)

ENERGY INTENSIVE PRIMARY RATE *EIP*

(Continued from Sheet No. D-37.20)

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 *0.850, 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 Customers.

Substation Ownership Credit: $(0.30) 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 Maximum Demand on each substation 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 Provision (SG):

Subject to any restrictions, as of June 8, 2012, this provision may be required for any Full Service Customer with a generating installation less than 550 kW operating in parallel with the Company's system, which may employ cogeneration or small power production technology.

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 own, operate and maintain all metering and auxiliary devices (including *telecommunication links) at the customer's expense. Meters furnished, installed and maintained by the Company shall meter generation equipment for customers that sell energy to the Company. No refund shall be made for any customer contribution required.*

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) Secondary Voltage or Primary Voltage service. The Company will determine the particular nature of the voltage in each case.

Self-generation customers requiring Company delivery service for any portion of the load that has been self-generated will be charged as described in the Delivery Charges section of this Rate Schedule.

There shall be no double billing of demand under the base rate and the Self-Generation Provision.

Sales of Self-Generated Energy to the Company:

A customer who meets the Federal Energy Regulatory Commission's (FERC) criteria for a Qualifying Facility may elect to sell energy to the Company. 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.

Where the customer elects to sell energy to the Company, an Interval Data Meter (IDM) or other applicable meter is required for their generator. 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.

Administrative Cost Charge:

$0.0010 per kWh purchased for generation installations with a capacity of 100 kW or less.

Energy Purchase:

An energy purchase by the Company shall be bought at the Midwest Independent Transmission System Operator's (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) less $0.005/kWh. The Company may discontinue purchases during system emergencies, maintenance and other operational circumstances.

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 applicable REP Surcharge and EE Surcharge shown on sheet D-2.10, *the LIEAF Surcharge on Sheet D-3.00* and capacity charges and the System Access Charge included in the rate.

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.

GENERAL SERVICE SELF GENERATION RATE GSG-2

(Continued From Sheet No. D-42.00)

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 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.

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.

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 Standby Demand

Charges for Customer Voltage Level 2 (CVL 2)

Capacity Charge:	$*2.29*	per kW of Standby Demand

Charges for Customer Voltage Level 1 (CVL 1)

Capacity Charge:	$*0.67*	per kW of Standby Demand

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-3.10 and the Securitization Charges shown on Sheet Nos. D-5.00 and D-5.10.

(Continued on Sheet No. D-44.00)

GENERAL SERVICE SELF GENERATION RATE GSG-2

(Continued From Sheet No. D-43.00)

Monthly Rate: (Contd)

Standby Charges: (Contd)

Adjustment for Power Factor:

For all energy supplied by the Company, the adjustment for the Power Factor shall be as provided for under the customer's otherwise applicable Company Full Service firm Rate Schedule.

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:

Substation Ownership Credit: $(0.30) per kW of Standby 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 Maximum Demand on each substation 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.

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: $ (0.67) per kW of Standby 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 Midwest Independent Transmission System Operator's (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) less $0.005/kWh.

General Terms:

This rate is subject to all general terms and conditions shown on Sheet No. D-1.00.

(Continued on Sheet No D-45.00)

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: $*0.054261* per kWh for all kWh

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-4.00.

(Continued on Sheet No. D-47.00)

GENERAL SERVICE METERED LIGHTING RATE GML
(Continued from Sheet No. D-46.00)

Monthly Rate: (Contd)

Secondary Delivery Charge:

System Access Charge:	$10.00	per customer per month
Distribution Charge:	$*0.054791*	per kWh for all kWh

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-3.10 and the Securitization Charges shown on Sheet Nos. D-5.00 and D-5.10.

Primary Power Supply Charge:

Energy Charge:	$*0.026628*	per kWh for all kWh

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-4.00.

Primary Delivery Charge:

System Access Charge:	$20.00	per customer per month
Distribution Charge:	$*0.041004*	per kWh for all kWh

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-3.10 and the Securitization Charges shown on Sheet Nos. D-5.00 and D-5.10.

Net Metering Program:

The Net Metering Program is available to any eligible customer as described in Rule C11., 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.B, Net Metering Program.

A customer who participates in the Net Metering Program is subject to the provisions contained in Rule C11., 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-48.00)

GENERAL SERVICE METERED LIGHTING RATE GML
(Continued from Sheet No. D-47.00)

Monthly Rate: (Contd)

General Terms:

This rate is subject to all general terms and conditions shown on Sheet No . D-1.00.

Minimum Charge:

The applicable REP Surcharge and EE Surcharge shown on sheet D-2.10*, the LIEAF Surcharge on Sheet D-3.00* and the System Access Charge included in the rate.

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.

Special Terms and Conditions:

The Company reserves the right to make special contractual arrangements as to term or duration of contract, termination charges, contribution in aid of construction, annual charges or other special considerations when the customer requests service, equipment or facilities not normally provided under this rate.

Hours of Lighting:

Metered Lights shall be controlled to burn only when the natural general level of illumination is lower than about 3/4 footcandle. Under normal conditions this is approximately one-half hour after sunset until approximately one-half hour before sunrise. For dusk to midnight service, luminaires shall be controlled to turn off anytime between 11:00 PM, Eastern standard time, and dawn. The turnoff time within a given municipality shall be the same at all locations.

Term and Form of Contract:

All service under this rate shall require a written contract with an initial term of five years or more.

M.P.S.C. No. 13 - Electric
Consumers Energy Company **Sheet No. D-51.00**

GENERAL SERVICE UNMETERED LIGHTING RATE GUL

(Continued From Sheet No. D-50.10)

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)	**Fixture Charge per Luminaire** (4)
Mercury Vapor (3)	100	128	3,500	$*5.45*	$6.00
Mercury Vapor (3)	175	209	7,500	*8.90*	6.00
Mercury Vapor (3)	250	281	10,000	*11.97*	6.00
Mercury Vapor (3)	400	458	20,000	*19.51*	6.00
Mercury Vapor (3)	700	770	35,000	*32.80*	6.00
Mercury Vapor (3)	1,000	1,080	50,000	*46.00*	6.00
High-Pressure Sodium (3)	70	83	5,000	*3.54*	6.00
High-Pressure Sodium	100	117	8,500	*4.98*	6.00
High-Pressure Sodium	150	171	14,000	*7.28*	6.00
High-Pressure Sodium (3)	200	247	20,000	*10.52*	6.00
High-Pressure Sodium	250	318	24,000	*13.54*	6.00
High-Pressure Sodium	400	480	45,000	*20.44*	6.00
Fluorescent (3)	380	470	20,000	*20.02*	6.00
Incandescent (3)	202	202	2,500	*8.60*	6.00
Incandescent (3)	305	305	4,000	*12.99*	6.00
Incandescent (3)	405	405	6,000	*17.25*	6.00
Incandescent (3)	690	690	10,000	*29.39*	6.00
Metal Halide	150	170	9,750	*7.24*	6.00
Metal Halide (3)	175	210	10,500	*8.94*	6.00
Metal Halide	250	290	15,500	*12.35*	6.00
Metal Halide	400	460	24,000	*19.59*	6.00

(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, Securitization and Securitization Tax Charges, Power Plant Securitization Charges and surcharges.

(3) Rates apply to existing luminaires only and are not open to new business.

(4) For customers who own their lighting fixtures and are assessed a Service Charge (but not a Fixture Charge), the charge per luminaire represents a *43*% Power Supply Charge and a *57*% Distribution Charge. For customers who do not own their lighting fixtures and are assessed both a Service Charge and a Fixture Charge, the charge per luminaire represents a *24.3*% Power Supply Charge and a *75.7*% 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-52.00)

GENERAL SERVICE UNMETERED LIGHTING RATE GUL

(Continued From Sheet No. D-53.00)

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 capacity requirements in watts of the lamp (s) including ballast(s) times the monthly Burning Hours as defined below divided by 1,000.

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 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. For 24-hour service, unmetered lighting shall be burning 24 hours per day.

The Company shall replace or repair, at its own cost, unmetered 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.

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.

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 UNMETERED EXPERIMENTAL LIGHTING RATE GU-XL

(Continued From Sheet No. D-54.01)

Facilities Policy (contd):

Company-Owned Option (contd)

D. The Company will determine the type and size of all experimental 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 experimental lighting available under this rate.
E. The Company shall determine all associated equipment necessary to provide service under the Company-Owned Unmetered Experimental Lighting option.
F. Any charges, deposits or contributions may be required in advance of commencement of construction.

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:

Power Supply Charges:

Energy Charge:	$*0.052307*	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:	$*0.054258*	per kWh for all kWh

Delivery Charges Company-Owned Option:

Distribution Charge:	$*0.055508*	per kWh for all kWh
Fixture Charge per Luminaire:	$6.00	per month

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-3.10 and the Securitization Charges shown on Sheet Nos. D-5.00 and D-5.10.

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 Experimental 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.

(Continued on Sheet No. D-54.03)

GENERAL UNMETERED EXPERIMENTAL LIGHTING RATE GU-XL

(Continued From Sheet No. D-54.02)

Maintenance of Lighting:

The Company shall replace or repair, at its own cost, Company-Owned Unmetered Experimental 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.

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.

Term and Form of Contract:

All service under this rate shall require a written contract with an initial term of two 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:	$*0.072771*	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:

System Access Charge:	$2.00	per customer per month
Distribution Charge:	$*0.014438*	per kWh for all kWh

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-3.10 and the Securitization Charges shown on Sheet Nos. D-5.00 and D-5.10.

(Continued on Sheet No. D-55.00)

GENERAL SERVICE UNMETERED RATE GU
(Continued from Sheet No. D-55.00)

Monthly Rate: (Contd)

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 applicable REP Surcharge and EE Surcharge shown on sheet D-2.10*, the LIEAF Surcharge on Sheet D-3.00* and the System Access Charge included in the rate.

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.

Special Terms and Conditions:

The Company reserves the right to make special contractual arrangements as to term or duration of contract, termination charges, contribution in aid of construction, monthly charges or other special considerations when the customer requests service, equipment or facilities not normally provided under this rate.

Term and Form of Contract:

Traffic Lighting, Wireless Access and Security Camera service under this rate may require a written contract for a term of reasonable duration.

All service under this rate to Community Antenna Television Service Companies shall require a written contract with a minimum term of one year.

(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, 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 load-profiled customer with maximum demand of 20 kW or less may receive meter reads by conventional means. If the load-profiled account exceeds a maximum demand of 20 kW, 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 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 that 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. 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 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.

RETAIL OPEN ACCESS PRIMARY RATE ROA-R

(Continued From Sheet No. E-22.00)

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 *7.239%* 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-3.10 and the Securitization Charges shown on Sheet Nos. D-5.00 and D-5.10. 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.

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 PRIMARY RATE ROA-S

(Continued From Sheet No. E-24.00)

Metering Requirements:

The ROA Customer with a Maximum Demand of less than 20 kW shall be separately metered by 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 AccessCharge, 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 an Interval Data Meterof 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 AccessCharge, 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 Metershall 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 *7.239%* 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-26.00)

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 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%	*0.784%*
Customer Voltage Level 2	*1.340%*	*2.434%*
Customer Voltage Level 3	*3.339%*	*7.239%*

(Continued on Sheet No. E-28.00)

MICHIGAN PUBLIC SERVICE COMMISSION

Case No.: U-17735
Attachment C

Consumers Energy Company
Summary of Present and Proposed Revenues by Rate Schedule
Including Classic 7 O&M Reduction
Total Revenues

Line No.	Description	(a) Sales	(b) Present Revenue	(c) Proposed Revenue	(d) Difference Revenue	(e) Difference Percent
		MWh	$000	$000	$000	%
	Bundled Service					
	Residential Class					
1	Residential Service RS	12,386,521	$ 1,756,640	$ 1,880,456	$ 123,816	7.0
2	Residential Time-of-Day RT	49,576	6,393	6,669	277	4.3
3	Residential Electric Vehicle REV	3,161	354	395	41	11.6
4	Res. Dynamic Price RSDP	-	-	-	-	NA
5	Res. Dynamic Price Rebate RSDPR	-	-	-	-	NA
6	Total Residential Class	12,439,258	1,763,387	1,887,521	124,134	7.0
	Secondary Class					
7	Secondary Energy-only GS	3,474,949	504,176	524,203	20,027	4.0
8	Sec. Energy Dynamic Price GSDP	-	-	-	-	NA
9	Secondary Demand GSD	4,017,015	498,550	513,483	14,933	3.0
10	Sec. Demand Dynamic Price GSDDP	-	-	-	-	NA
11	Total Secondary Class	7,491,964	1,002,726	1,037,686	34,960	3.5
	Primary Class					
12	Primary Energy-only GP	1,407,804	147,950	152,503	4,553	3.1
13	Pri. Energy Dynamic Price GPDP	-	-	-	-	NA
14	Primary Demand GPD	9,343,402	824,298	797,337	(26,960)	(3.3)
15	Primary Energy Intensive Rate EIP/MMPP	355,201	22,424	22,214	(210)	(0.9)
16	Primary Time of Use Pilot GPTU	205,807	18,165	18,985	820	4.5
17	Large Economic Development E-1[1]	1,778,677	102,212	112,652	10,440	10.2
18	Total Primary Class	13,090,891	1,115,048	1,103,691	(11,357)	(1.0)
		11,312,214	1,012,836 -	991,040	(21,797)	(2.2)
	Lighting & Unmetered Class					
19	Metered Lighting Service GML	8,058	900	912	12	1.4
20	Unmetered Lighting Service GUL	131,024	30,303	28,376	(1,928)	(6.4)
21	Unmetered Exp. Lighting GU-XL	-	-	-	-	NA
22	Unmetered Service GU	86,458	7,751	7,610	(142)	(1.8)
23	Total Lighting & Unmetered Class	225,540	38,954	36,897	(2,057)	(5.3)
	Self-generation Class					
24	Small Self-generation GSG-1	-	-	-	-	NA
25	Large Self-generation GSG-2	46,865	3,207	1,527	(1,680)	(52.4)
26	Total Self-Generation Class	46,865	3,207	1,527	(1,680)	(52.4)
27	Total Bundled Service	33,294,517	$ 3,923,322	$ 4,067,323	$ 144,000	3.7
	ROA Service					
	Residential Class					
28	Residential Service RS	-	$ -	$ -	$ -	NA
29	Residential Time-of-Day RT	-	-	-	-	NA
30	Total Residential Class	-	-	-	-	NA
	Secondary Class					
31	Secondary Energy-only GS	24,640	936	1,060	124	13.3
32	Secondary Demand GSD	210,891	6,375	7,172	798	12.5
33	Total Secondary Class	235,532	7,311	8,233	922	12.6
	Primary Class					
34	Primary Energy-only GP	51,324	813	881	68	8.4
35	Primary Demand GPD	3,779,243	26,871	21,841	(5,030)	(18.7)
36	Total Primary Class	3,830,567	27,684	22,722	(4,962)	(17.9)
37	Total ROA Service	4,066,098	$ 34,995	$ 30,955	$ (4,040)	(11.5)
38	Total Bundled and ROA Service	37,360,615	$ 3,958,317	$ 4,098,278	$ 139,960	3.5

[1] Present Revenue reflects a 5/1/15 - 11/30/15 at E-1 rate, remaining at present GPD, proposed revenue reflects a full year at the proposed GPD rates

MICHIGAN PUBLIC SERVICE COMMISSION

Consumers Energy Company
Summary of Present and Proposed Revenues by Rate Schedule
Including Classic 7 O&M Reduction
Power Supply Revenues

Line No.	Description	(a) Sales	(b) Present Revenue	(c) Proposed Revenue	(d) Difference Revenue	(e) Difference Percent
		MWh	$000	$000	$000	%
	Bundled Service					
	Residential Class					
1	Residential Service RS	12,386,521	$ 1,104,717	$ 1,207,859	$ 103,143	9.3
2	Residential Time-of-Day RT	49,576	4,082	4,276	194	4.8
3	Residential Electric Vehicle REV	3,161	183	219	36	19.6
4	Res. Dynamic Price RSDP	-	-	-	-	NA
5	Res. Dynamic Price Rebate RSDPR	-	-	-	-	NA
6	Total Residential Class	12,439,258	1,108,982	1,212,355	103,373	9.3
	Secondary Class					
7	Secondary Energy-only GS	3,474,949	330,289	331,483	1,194	0.4
8	Sec. Energy Dynamic Price GSDP	-	-	-	-	NA
9	Secondary Demand GSD	4,017,015	371,912	371,666	(246)	(0.1)
10	Sec. Demand Dynamic Price GSDDP	-	-	-	-	NA
11	Total Secondary Class	7,491,964	702,200	703,149	948	0.1
	Primary Class					
12	Primary Energy-only GP	1,407,804	124,867	127,392	2,526	2.0
13	Pri. Energy Dynamic Price GPDP	-	-	-	-	NA
14	Primary Demand GPD	9,343,402	744,848	728,428	(16,420)	(2.2)
15	Primary Energy Intensive Rate EIP/MMPP	355,201	21,206	21,020	(186)	(0.9)
16	Primary Time of Use Pilot GPTU	205,807	15,827	16,327	500	3.2
17	Large Economic Development E-1	1,778,677	84,240	131,674	47,435	56.3
18	Total Primary Class	13,090,891	990,987	1,024,841	33,854	3.4
	Lighting & Unmetered Class					
19	Metered Lighting Service GML	8,058	458	438	(20)	(4.4)
20	Unmetered Lighting Service GUL	131,024	8,000	6,815	(1,185)	(14.8)
21	Unmetered Exp. Lighting GU-XL	-	-	-	-	NA
22	Unmetered Service GU	86,458	6,637	6,350	(287)	(4.3)
23	Total Lighting & Unmetered Class	225,540	15,095	13,603	(1,493)	(9.9)
	Self-generation Class					
24	Small Self-generation GSG-1	-	-	-	-	NA
25	Large Self-generation GSG-2	46,865	2,512	-	(2,512)	(100.0)
26	Total Self-Generation Class	46,865	2,512	-	(2,512)	(100.0)
27	Total Bundled Service	33,294,517	$ 2,819,777	$ 2,953,947	$ 134,170	4.8
	ROA Service					
	Residential Class					
28	Residential Service RS	-	$ -	$ -	$ -	NA
29	Residential Time-of-Day RT	-	-	-	-	NA
30	Total Residential Class	-	-	-	-	NA
	Secondary Class					
31	Secondary Energy-only GS	24,640	-	-	-	NA
32	Secondary Demand GSD	210,891	-	-	-	NA
33	Total Secondary Class	235,532	-	-	-	NA
	Primary Class					
34	Primary Energy-only GP	51,324	-	-	-	NA
35	Primary Demand GPD	3,779,243	-	-	-	NA
36	Total Primary Class	3,830,567	-	-	-	NA
37	Total ROA Service	4,066,098	$ -	$ -	$ -	NA
38	Total Bundled and ROA Service	37,360,615	$ 2,819,777	$ 2,953,947	$ 134,170	4.8

MICHIGAN PUBLIC SERVICE COMMISSION

Consumers Energy Company
Summary of Present and Proposed Revenues by Rate Schedule
Including Classic 7 O&M Reduction
Delivery Revenues

Line No.	Description	(a) Sales	(b) Present Revenue	(c) Proposed Revenue	(d) Difference Revenue	(e) Difference Percent
		MWh	$000	$000	$000	%
	Bundled Service					
	Residential Class					
1	Residential Service RS	12,386,521	$ 651,923	$ 672,596	$ 20,673	3.2
2	Residential Time-of-Day RT	49,576	2,310	2,393	83	3.6
3	Residential Electric Vehicle REV	3,161	171	176	5	3.1
4	Res. Dynamic Price RSDP	-	-	-	-	NA
5	Res. Dynamic Price Rebate RSDPR	-	-	-	-	NA
6	Total Residential Class	12,439,258	$ 654,405	675,166	20,761	3.2
	Secondary Class					
7	Secondary Energy-only GS	3,474,949	173,888	192,720	18,832	10.8
8	Sec. Energy Dynamic Price GSDP	-	-	-	-	NA
9	Secondary Demand GSD	4,017,015	126,638	141,818	15,180	12.0
10	Sec. Demand Dynamic Price GSDDP	-	-	-	-	NA
11	Total Secondary Class	7,491,964	300,526	334,538	34,012	11.3
	Primary Class					
12	Primary Energy-only GP	1,407,804	23,083	25,111	2,028	8.8
13	Pri. Energy Dynamic Price GPDP	-	-	-	-	NA
14	Primary Demand GPD	9,343,402	79,449	68,910	(10,540)	(13.3)
15	Primary Energy Intensive Rate EIP/MMPP	355,201	1,218	1,194	(24)	(2.0)
16	Primary Time of Use Pilot GPTU	205,807	2,338	2,658	320	13.7
17	Large Economic Development E-1	1,778,677	17,972	(19,023)	(36,995)	(205.8)
18	Total Primary Class	13,090,891	124,061	78,850	(45,211)	(36.4)
	Lighting & Unmetered Class					
19	Metered Lighting Service GML	8,058	442	474	32	7.3
20	Unmetered Lighting Service GUL	131,024	22,303	21,561	(742)	(3.3)
21	Unmetered Exp. Lighting GU-XL	-	-	-	-	NA
22	Unmetered Service GU	86,458	1,114	1,260	146	13.1
23	Total Lighting & Unmetered Class	225,540	23,859	23,294	(564)	(2.4)
	Self-generation Class					
24	Small Self-generation GSG-1	-	-	-	-	NA
25	Large Self-generation GSG-2	46,865	695	1,527	832	119.6
26	Total Self-Generation Class	46,865	695	1,527	832	119.6
27	Total Bundled Service	33,294,517	$ 1,103,545	$ 1,113,375	$ 9,830	0.9
	ROA Service					
	Residential Class					
28	Residential Service RS	-	$ -	$ -	$ -	NA
29	Residential Time-of-Day RT	-	-	-	-	NA
30	Total Residential Class	-	-	-	-	NA
	Secondary Class					
31	Secondary Energy-only GS	24,640	936	1,060	124	13.3
32	Secondary Demand GSD	210,891	6,375	7,172	798	12.5
33	Total Secondary Class	235,532	7,311	8,233	922	12.6
	Primary Class					
34	Primary Energy-only GP	51,324	813	881	68	8.4
35	Primary Demand GPD	3,779,243	26,871	21,841	(5,030)	(18.7)
36	Total Primary Class	3,830,567	27,684	22,722	(4,962)	(17.9)
37	Total ROA Service	4,066,098	$ 34,995	$ 30,955	$ (4,040)	(11.5)
38	Total Bundled and ROA Service	37,360,615	$ 1,138,540	$ 1,144,330	$ 5,790	0.5

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(Continued From Sheet No. A-4.00)

SECTION D
RATE SCHEDULES (Contd)

(Continued on Sheet No. A-6.00)

TECHNICAL TERMS AND ABBREVIATIONS
(FOR ALL CUSTOMERS)

I. The definitions of the following technical terms and abbreviations are applicable to the Company's Electric Rate Book and are not contained in the other Sections thereof:

A. For All Utilities

(1) "Commission" means the Michigan public service commission.
(2) "Effective Date" means the date when the tariff sheet must be followed.
(3) "Issue Date" means the date the Company files a tariff sheet with the Commission.
(4) "Rate Book" means the complete set of Company filings submitted in accordance with the "Filing Procedures for Electric, Wastewater, Steam and Gas Utilities".
(5) "Rate Schedule" or "Rider" means the rate or charge for a particular classification of service, including all special terms and conditions under which that service is furnished at the prescribed rate or charge.
(6) "Rate Sheet" or "Tariff Sheet" means any of the documents filed in accordance with "Filing Procedures for Electric, Wastewater, Steam and Gas Utilities".
(7) "Rules and Regulations" means the rules, regulations, practices, classifications, exceptions, and conditions that the Company must observe when providing service.
(8) "Standard Customer Forms Index" means a listing showing the number, title, and revision date for all standard forms, in any format (preprinted or electronically preformatted) that the Company uses to document contracts or other agreements that create or alter a customer's rights or responsibilities in dealings with the Company. Standard customer forms require a customer signature or are specifically referenced within the Rate Book for execution between the Company and customers.

B. Company

Advance - For the purposes of deposits and contributions, "in advance" means in advance of commencement of construction.

Ampere (A) - Unit of electrical current produced in a circuit by one volt acting across resistance of one ohm. It is also proportional to the quantity of electrons flowing through a conductor past a given point in one second.

Bona Fide Change in Customer Load - A change in customer load made in good faith without fraud or deceit.

Commercial Usage for Emergency Electrical Procedures - Usage for applications, other than residential, associated with businesses and other establishments which qualify for a nonmanufacturing industry code under the most current edition of the Standard Industrial Classification Manual. In addition to the usual retail and service businesses included are communication, transportation, utility, recreation, education, religious, social and governmental businesses or institutions. It also includes usage for business offices and common use facilities associated with centrally metered complexes (apartments, condominiums, and trailer parks).

Company - Consumers Energy Company.

Customer Voltage Level 1 – Service supplied either directly from the Company's distribution system when the voltage is 120,000 Volts or greater or from this system through a Company-owned substation where, from the exits of the substation, the distribution equipment for supplying service is owned and maintained by the customer.

(Continued on Sheet No. A-30.00)

(Continued From Sheet No. C-1.00)

C1. CHARACTERISTICS OF SERVICE (Contd)

C1.3 Use of Service

The customer shall use the service so as not to cause a safety hazard, endanger the Company facilities or the customer's equipment or to disturb the Company's service to other customers. The Company disclaims any responsibility to inspect the customer's wiring or equipment and shall not be held liable for any injury, damage or overbilling resulting from the condition thereof, or from any of the circumstances described in Paragraphs A through O below in this rule.

The Company reserves the right to deny or shut off service in accordance with Rules and Regulations of the Company or Commission under the following conditions or for any of the following reasons:

A. Without prior notice to any customer for a condition on the customer's premises which is determined by the Company or a code authority to be hazardous.

B. Without prior notice if the customer uses equipment in a manner which adversely affects the Company's equipment or the Company's service to others.

C. To any customer involved in metered or unmetered energy theft, including obtaining the use of equipment by submitting a falsified application. Energy theft includes but is not limited to:

(1) Tampering
(2) Unauthorized Use
(3) Diversion
(4) Interference

D. For misrepresentation of identity for the purpose of obtaining utility service.

E. For failure of the customer to permit the Company reasonable access to equipment installed upon the premises for the purpose of inspection, meter reading, maintenance, replacement or removal.

F. For failure of the customer to install and/or maintain necessary devices to protect his/her equipment in the event of service interruptions and other disturbances on the Company's Distribution system.

G. For failure of the customer to install and/or maintain necessary devices to protect the Company's facilities against overload caused by the customer's equipment.

H. For failure of the customer to fulfill contractual obligations for service or facilities.

I. For failure of the customer to obtain all permits and inspections of customer's wiring or equipment required by applicable law.

J. For failure of the reselling customer to comply with Rule C4.4, Resale.

K. For failure of the customer to post a cash security deposit or other form of guarantee, when required in accordance with these Rules and Regulations.

L. For failure of the customer to pay a delinquent account not in dispute.

(Continued on Sheet No. C-3.00)

(Continued From Sheet No. C-3.00)

C1. CHARACTERISTICS OF SERVICE (Contd)

C1.4 Extraordinary Facility Requirements and Charges (contd)

Contribution In Aid of Construction Allowance Schedule

Schedule	Customer Voltage Level(CVL)	With a Full Service Contract, by Contract Duration					Without Full Service Contract
		1 Year	2 Year	3 Year	4 Year	5 Year	
General Service Primary Rate GP	1	$*0.024*/kWh	$*0.034*/kWh	$*0.049*/kWh	$*0.064*/kWh	$*0.077*/kWh	$*0.024*/kWh
	2	$*0.032*/kWh	$*0.045*/kWh	$*0.065*/kWh	$*0.084*/kWh	$*0.101*/kWh	$*0.032*/kWh
	3	$*0.051*/kWh	$*0.055*/kWh	$*0.080*/kWh	$*0.103*/ kWh	$*0.124*/kWh	$*0.051*/kWh
General Service Primary Demand Rate GPD	1	$*30*/kW	$*55*/kW	$*80*/kW	$*100*/kW	$*120*/kW	$*25*/Kw
	2	$*80*/kW	$*135*/kW	$*195*/kW	$*250*/kW	$*300*/kW	$*80*/kW
	3	$*140*/kW	$*185*/kW	$*270*/kW	$*345*/kW	$*420*/kW	$*140*/kW
Energy Intensive Primary Rate *EIP*	1	$*0*/kW	$*0*/kW	$*0*/kW	$*0*/kW	$*0*/kW	NA
	2	$*25*/kW	$*50*/kW	$*70*/kW	$*90*/kW	$*110*/kW	NA
	3	$*65*/kW	$*120*/kW	$*175*/kW	$*225*/kW	$*270*/kW	NA

The Company reserves the right to make special contractual arrangements as to the provision of necessary Service Facilities, duration of contract, minimum bills, require upfront deposit and other service conditions, including, but not limited to, when the customer's load requirements are of a short-term duration, temporary or a transient nature, or if in the opinion of the Company, the customer does not have acceptable credit history or represents an unacceptable credit risk or other reasons within the sound discretion of the Company.

C1.5 Invalidity of Oral Agreements or Representations

When a written contract is required, no employee or agent of the Company is authorized to modify or supplement the Rules and Regulations and Rate Schedules of the Electric Rate Book by oral agreement or representation, and no such oral agreement or representation shall be binding upon the Company.

(Continued on Sheet No. C-4.00)

(Continued From Sheet No. C-19.00)

C4. APPLICATION OF RATES (Contd)

C4.2 Choice of Rates (Contd)

After the customer has selected the rate and rate provision under which service shall be provided, the customer shall not be permitted to change from that rate and rate provision to another until at least twelve months have elapsed. The customer shall not be permitted to evade this rule by temporarily terminating service. However, the Company may, at its option, waive the provisions of this paragraph where it appears a change is for permanent rather than for temporary or seasonal advantage. The provisions of this paragraph may also be waived where the customer can demonstrate that a Bona Fide Change in Customer Load has occurred. The effective date of a rate change under this rule shall be the beginning read date of the next bill issued. The intent of this rule is to prohibit frequent shifts from rate to rate.

The Company shall not make refunds in instances where the customer would have paid less for service had the customer been billed on another applicable rate or provision rate.

Where the customer has provided the Company with incorrect information to gain an economic benefit, backbilling may be rendered to the date the incorrect rate selection initially occurred.

In order to reduce load in times of high system demands, the Company may make contractual arrangements with customers who can self-generate power, shift load from on-peak to off-peak periods and/or provide other forms of voluntary load reduction.

C4.3 Application of Residential Usage and Non-Residential Usage

A. Residential Usage and Rate Application

(1) General

For purposes of rate application "residential usage" shall be usage metered and consumed within an individual household, and reasonably appurtenant and related to and normally associated with such a household, for such applications as space conditioning, cooking, water heating, refrigeration, clothes drying, incineration, lighting and other similar household applications.

The term "household" includes single-family homes, farm homes, seasonal dwellings, duplexes, and individual living units within mobile home parks, condominiums, apartments and cooperatives; provided, however, to qualify for residential usage a household must have the normal household facilities such as bathroom, individual cooking and kitchen sink facilities and have received an occupancy permit or similar instrument, if issued, by the local governing authority. *Customers requiring temporary electric service for a residential dwelling under construction shall be served under the General Service Secondary Rate GS – Commercial – Temporary Construction Service until a permit for occupancy is obtained for the premises.*

At the time a new service or a rate change is requested, the Company shall advise the customer in the selection of the rate or rate provision which will give the customer the lowest cost of service based on the information provided to the Company. The Company's recommendation will be based upon the customer's energy usage and responses to the following criteria: (a) type of dwelling, (b) meets the requirements for Income Assistance Service Provision, and (c) meets the requirements for Senior Citizen Service Provision.

(Continued on Sheet No. C-21.00)

(Continued From Sheet No. C-21.00)

C4. APPLICATION OF RATES (Contd)

C4.3 Application of Residential Usage and Non-Residential Usage (Contd)

A. Residential Usage and Rate Application (Contd)

(c) Multifamily Dwellings Served Through a Single Meter

A multifamily dwelling served through a single meter shall be billed as follows:

(i) Dwellings containing two households, including common area, shall be billed on Residential Service Secondary Rate RS.

(ii) Dwellings containing three or four households, including common area, shall be billed on Residential Service Secondary Rate RS or the appropriate General Service Rate.

(iii) Dwellings containing five or more households, including common area, shall be billed on the appropriate General Service Rate.

(5) Farm Service

Service shall be available to farms for residential use under the appropriate Residential Service Secondary Rate. *Service* may be used through the same meter so long as such use is confined to single-phase or three-phase secondary service where electric energy is used for the culture, processing and handling of products grown or used on the customer's farm. The qualifying small farm customer must be the owner and operator of the farm, a physical occupant of the main household which is used as the customer's principal residence, and the associated farm buildings/facilities must be located on the same premises as the main household. Use of service for purposes other than set forth above shall be served and billed on the appropriate General Service Rate.

In general, the entire electrical needs of the farm operation and residence on a single premises shall be served through a single meter. A second meter on a General Service Rate may be allowed on the premises for a portion of the farm operation if a representative of the Company determines that it is impractical to serve the load through a single metering installation.

B. Non-Residential Usage and Rate Application

For purposes of rate application, "Non-Residential usage" shall be usage metered and consumed that does not qualify for residential usage. Non-Residential usage includes usage associated with the purchase, sale, or supplying (for profit or otherwise) of a commodity or service by a public or private person, entity, organization or institution. Non-Residential usage includes usage associated with penal institutions, corrective institutions, motels, hotels, separately metered swimming pool heater usage, yachts, boats, tents, campers or recreational vehicles.

Non-Residential usage shall be billed on the Company's appropriate General Service Rate.

Tourist homes, rooming houses, dormitories, nursing homes and other similarly occupied buildings containing sleeping accommodations for more than six persons shall be classified as Non-Residential and billed on the appropriate General Service Rate. The landlord and his/her immediate family are not included in the six-person rule.

Rules for Multifamily Dwellings and Farm Service can be found in Sections A(4) and (5) of this rule.

(Continued on Sheet No. C-23.00)

(Continued From Sheet No. C-23.00)

C4. APPLICATION OF RATES (Contd)

C4.3 Application of Residential Usage and Non-Residential Usage (Contd)

D. Rate Application for Seasonal Condominium Campgrounds (Contd)

(5) The customer must notify individuals and/or co-owners utilizing the customer's property that the customer's facilities may not be able to be located by Miss Dig.

(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 Demand Rate GSD, General Service Primary Rate GP, or General Service Primary Demand Rate GPD. 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 RS 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, Residential Service Time-of-Day Secondary Rate RT 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:

$*0.145455* per kWh for all kWh during the months of June-September
$*0.137980* 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-25.00)

(Continued From Sheet No. C-24.00)

C4. APPLICATION OF RATES (Contd)

C4.4 Resale (Contd)

The service contract shall also provide that the reselling customer shall be responsible for the testing of each ultimate user's meter at least once every 3 years. The accuracy of such meters shall be maintained within the limits as prescribed in Rule B1., Technical Standards for Electric Service. Meters shall be tested only by outside testing services or laboratories approved by the Company.

A record of each meter, including testing results, shall be kept by the reselling customer during use of the meter and for an additional period of one year thereafter. When requested, the reselling customer shall submit certified copies of the meter test results and meter records to the Company.

The reselling customer shall supply each ultimate user with an electric system adequate to meet the needs of the ultimate user with respect to the nature of service, voltage level and other conditions of service. The reselling customer shall render a bill once during each billing month to each of the customer's tenants in accordance with approved Rate Schedules of the Company. Every bill rendered by the reselling customer shall specify the following information: the rate categories and provisions; the due date; the beginning and ending meter readings of the billing period and dates thereof; the difference between the meter readings; the Power Supply Cost Recovery Factor; if applicable; the subtotal of the bill before taxes; amount of sales tax; other local taxes where applicable; any previous balance; the amount due for delivery service and/or power supply service, as applicable; the amount due for other authorized charges; and the total amount due. The due date of the customer's bill shall be 21 days from the date of rendition.

If the reselling customer fails to meet the obligations of this rule, the Company shall notify the Commission. If, after review with the reselling customer, the problem is not resolved, the Company shall assess a penalty in the amount of 2% of the resale customer's bill before taxes per month *until the problem is resolved*. If the problem is not resolved after three months, the Company shall shut off electric service until the problem is resolved. The Company shall not incur any liability as the result of this shutoff of electric service.

The renting of premises with the cost of electric service included in the rental as an incident of tenancy is not considered to be a resale of such service.

C4.5 Mobile Home Park - Individually Served

For purposes of this rule, the definition of a mobile home park is a parcel or tract of land upon which three or more mobile homes are located on a continuous nonrecreational basis.

Service to separately metered mobile homes shall be billed on the appropriate Residential Service Rate under the following conditions:

Service to all new mobile home parks and expanded service to existing mobile home parks receiving electrical service shall be provided through individual tenant metering.

The mobile home park shall be of a permanent nature with improved streets and with individual water and sewer connections to each lot. Ordinarily, electric service to a mobile home shall be in the name of the occupant. However, service to lots designated for occasional or short-term occupancy shall be in the name of the owner of the park or his/her authorized representative.

(Continued on Sheet No. C-26.00)

(Continued From Sheet No. C-30.00)

C5. CUSTOMER RESPONSIBILITIES (Contd)

C5.2 Bills and Payments (Contd)

J. Energy Theft, Stolen Meter and Switched Meter

In cases where metered or unmetered energy theft, stolen meter or switched meter by someone other than a Company representative are involved, refunds and backbillings are for the determined duration of the period. Where the duration cannot be reasonably established or estimated, the Company will adjust the billing for the past three years on the basis of actual monthly consumption determined from the most recent 36 months of consumption data.

Metered or unmetered energy theft includes but is not limited to tampering, unauthorized use, diversion and interference. For purposes of this rule, a stolen meter is classified as any meter not specifically assigned to that service location by the Company. For purposes of this rule, a switched meter is classified as a meter intentionally assigned incorrectly to a customer resulting in the customer being billed for another customer's consumption.

The Company reserves the right to recover all unbilled service revenue and reasonable actual costs associated with the theft of energy, stolen meters or switched meters. Therefore, the customer or other user who benefits from the unauthorized or fraudulent use is responsible for payment of the reasonable actual cost of the service used during the period such fraudulent or unauthorized use or tampering occurred, or is reasonably assumed to have occurred, and is responsible for the reasonable actual cost of the tampering investigation and any associated damages, with the exception that all costs be recovered in cases involving criminal prosecution. The customer who did not intentionally steal a meter, switch a meter or who did not intentionally become involved in energy theft shall pay for energy usage according to Section H of this rule.

The owner of the multiple metered building shall be responsible for accurately tracing all lines and for tagging such lines with Company-provided tags to assure individual units are properly metered. The Company will not set the meters until the lines are identified. The owner of the multiple metered building could be held responsible for any underrecovery of revenues resulting from improperly tagged meters. Any future expense of tracing lines due to instances of switched meters related to errors in tracing and tagging of such lines shall be the responsibility of the current owner of the multiple metered building.

C5.3 Restoration of Service

Restoration charges and meter relocation charges shall be made by the Company to partially cover the cost of shutting off, terminating and restoring service.

Where service has been shut off for reasons as outlined in Rule C1.3, Use of Service, a restoration charge of $50 shall be collected from the customer whose service was disconnected at the customer's meter. If service was disconnected at the point of contact with the Company's distribution system, a charge of $80 shall be collected from the customer whose service was shut off.

Where service has been shut off for reasons as outlined in Rule C1.3, Use of Service, a meter relocation charge, if applicable, and assessed in accordance with Rule B2., Consumer Standards and Billing Practices for Electric and Gas Residential Service, R 460.116, Meter Accuracy, Meter Errors, Meter Relocations, and R 460.144, Restoration of Service, shall be collected from the customer whose service was shut off. The Company shall charge the customer for relocating the meter, based on the Company's current cost.

(Continued on Sheet No. 32.00)

(Continued From Sheet No. C-31.00)

C5. CUSTOMER RESPONSIBILITIES (Contd)

C5.3 Restoration of Service (Contd)

The restoration charge and meter relocation charge, if applicable, shall be billed to the customer and shall be paid before service is restored.

An On-Premises *Site Visit* Charge of $15.00 shall be assessed to the customer if a Company employee is sent to the premises to either serve the customer with a shut-off notification or to shut off service, unless the customer presents evidence that reasonably indicates the claim has been satisfied or is currently In Dispute. The *charge shall be applied* to the customer account. The Company shall not assess this fee twice on the same notice for shutoff.

In case of shutoff of service, the Company shall restore service only after any metering changes, where deemed necessary by the Company, have been made by the Company and after the customer has paid for any unmetered energy used, paid for any damage to Company property, paid the restoration charge and meter relocation charge, installed any necessary devices to protect the Company's facilities and paid all charges as provided in the Company's Electric Rate Book.

A customer who orders a termination and a restoration of service at the same premises within a 12-month period shall be liable for a "turnon" charge of $50.

C5.4 Shutoff Protection Plan for Residential Customers

A. Eligibility

Eligible low-income customers and senior citizen customers may choose to participate in the Shutoff Protection Plan (SPP) in lieu of the applicable Winter Protection Plan as described in Rule B2., Consumer Standards and Billing Practices for Electric and Gas Residential Service, R 460.148, Winter Protection Plan for Low-income Customers, or R 460.149, Winter Protection Plan for Senior Citizens. For purposes of this Company rule, an eligible low-income customer means a utility customer who has not had more than one default condition on the SPP in the last twelve months and whose household income does not exceed 200% of the federal poverty guidelines as published by the United States Department of Health and Human Services or who receives supplemental security income or low-income assistance through the Department of Human Services or successor agency, food stamps, or Medicaid. In addition, an eligible senior citizen customer means a utility customer who has not had more than one default condition on the SPP in the last twelve months, is 65 years of age or older, and advises the utility of his or her eligibility. An eligible customer enrolled in the SPP shall be referred to as an SPP Customer. Customers who are actively participating in the Consumers Affordable Resource for Energy (CARE) Pilot or have participated in the CARE Pilot during the concurrent heating season are not eligible to participate in SPP until the beginning of the next heating season.

(Continued on Sheet No. C-32.10)

(Continued From Sheet No. C-32.10)

C5. CUSTOMER RESPONSIBILITIES (Contd)

C5.4 Shutoff Protection Plan for Residential Customers (Contd)

D. Default

Should a SPP Customer fail to make payment by the due date, a shutoff notice specific to this SPP shall be issued but shall comply with the requirements of Part 8 of Rule B2., Consumer Standards and Billing Practices for Electric and Gas Residential Service. If the SPP Customer makes payment before the date provided for shutoff of service, the customer shall not be considered to be in default but shall remain in the SPP. If the SPP Customer makes payment after this date, the SPP Customer shall be in default and shall be removed from the SPP. The customer shall be subject to shutoff, provided the 24-hour notice was made by the Company.

E. Participation in Other Shutoff Protection Plans

Customers eligible to participate under the Winter Protection Plan, Rules R 460.148 and R 460.149, will be required to waive their rights to participate under the Winter Protection Plan in order to participate in the Plan. Upon enrollment, the Company shall send written confirmation of the enrollment terms and include notice of this provision.

C5.5 Non-Transmitting Meter Provision

Customers served on Residential Service Secondary Rates RS and General Service Secondary Rates GS have the option to choose a non-transmitting meter.

In order for a customer to be eligible to participate in the Non-Transmitting Meter Provision, the customer must have a meter that is accessible to Company employees and the customer shall have zero instances of unauthorized use, theft, fraud and/or threats of violence toward Company employees.

Customers electing a non-transmitting meter will pay the following charges per premises:

Up Front Charge:	$ 69.39	a one-time charge per premise per request if the notice is given before the transmitting meter is installed
	OR	
	$123.91	a one-time charge per premise per request if the notice is given after the transmitting meter is installed
Monthly Charge:	$ 9.72	per month at each premise

All standard charges and provisions of the customer's applicable tariff shall apply.

(Continued on Sheet No. C-32.30)

(Continued From Sheet No. *C-32.30*)

C6. DISTRIBUTION SYSTEMS, LINE EXTENSIONS AND SERVICE CONNECTIONS (Contd)

C6.1 Overhead Extension Policy (Contd)

A. Residential Customers (contd)

The Company shall make a one-time refund, five years from the completion date of the extension or upon completion of the customer's construction, whichever the customer chooses, of $500 for each additional residential customer and/or the first year's estimated revenue for each additional General Service customer who connects directly to the line for which a deposit was required. Refund allowances shall first be credited against the 25% reduction before a refund is made to the customer based on the customer's cash deposit. Directly connected customers are those who do not require the construction of more than 300 feet of Primary and/or Secondary distribution line. Refunds shall not include any amount of contribution in aid of construction for underground service made under the provisions of Rule C6.2, Underground Policy.

B. General Service Customers

The Company shall construct single-phase and three-phase distribution line extensions, at its own cost when the cost of such extension does not exceed three times the estimated annual revenue from the customer(s) to be immediately served.

Extensions in excess of the above free allowance shall require a deposit from the customer, in an amount equal to the estimated construction costs in excess of the free allowance.

(1) Original Customers

At the end of the first complete 12-month period beginning the month following the date the line extension is completed, the Company shall refund to the depositor three times the amount that actual revenue exceeds the original revenue estimate. If the actual revenue exceeds the estimated revenue, the actual revenue then becomes the base upon which future refund calculations are to be made during the remainder of the five-year refund period.

(2) Additional Connected Customers

The Company shall refund $500 for each residential customer and/or the first year's estimated revenue for each General Service customer who connects directly to the line for which a deposit was required. Directly connected customers are those who do not require the construction of more than 300 feet of Primary and/or Secondary distribution line. Refunds shall not be made until the original customer(s) or equivalent is actually connected to the extension. Refunds shall not include any amount of contribution in aid of construction for underground service made under the provisions of Rule C6.2, Underground Policy.

C. General

(1) Refundable deposits made with the Company under this rule shall be subject to refund without interest, for a five-year period which begins the month after the line extension is completed. The Company shall have no further obligation to refund any remaining portion of line extension deposits.

(2) Each extension shall be a separate, distinct unit and any further extension therefrom shall have no effect upon the agreements under which existing extensions were constructed.

(3) Refunds cannot exceed the refundable portion of the deposit

(4) Estimated construction costs shall exclude services and meters.

(5) The applicant shall furnish, without cost to the Company, all necessary rights-of-way and tree trimming permits, in a form satisfactory to the Company. If the applicant is unable to secure rights-of-way and permits, in a form satisfactory to the Company, the Company shall extend its distribution system along an alternate route selected by the Company, and shall require the applicant to pay all additional costs incurred.

(Continued on Sheet No. C-34.00)

(Continued From Sheet No. C-36.00)

C6. DISTRIBUTION SYSTEMS, LINE EXTENSIONS AND SERVICE CONNECTIONS (Contd)

C6.2 Underground Policy (Contd)

B. Installations of Underground Distribution Facilities - Residential (Contd)

Where a residential underground distribution system serves lots on one side of a street, the later connection of lots on the other side of the street to that existing system shall be considered as an original installation of a residential underground distribution system for such later-connected lots.

Streetlighting, if any, shall be served underground in areas served directly by residential underground distribution systems. The character and location of the streetlighting cables, if any, and all equipment constituting the residential underground distribution system, shall conform to specifications prepared by the Company.

Where the underground cable for a residential underground distribution system extends through areas within the subdivision which are undeveloped or consist of lots platted for future use and which are not to be served initially by the system, the front-foot measurement of both sides of the street or easement along which the cable extends through such areas shall be included in determining the contribution of the owner(s) or developer(s) for the residential underground distribution system.

Where the Company and the owner(s) or developer(s) agree that it is desirable to extend the underground cable to the boundary of a subdivision property from a point outside the subdivision a contribution of $7.00 per trench foot shall be required.

(b) Outside of subdivisions

The Company shall extend its Primary or Secondary distribution system from existing overhead or underground facilities. When any such extension is made from an existing overhead system the property owner may be required to provide an easement(s) for extension of the overhead system to a pole on his/her property where transition from overhead to underground can be made.

The customer shall be required to make a nonrefundable contribution in aid of construction to the Company, to cover the estimated total difference in cost between overhead and direct burial underground facilities for all underground facilities required to serve the customer.

(3) Installation of Underground Service Connections

The developer or customer shall be required to make a nonrefundable contribution in aid of construction to the Company, to cover the additional cost resulting from the installation of an underground service connection. For normal installations such contribution shall be computed on the basis of *a flat fee of $350.00 for the first 150 linear feet of service* from the termination of the Company's facilities at the front or rear property line to a point directly below the customer's meter. *Each additional foot of installation in excess of 150 linear feet shall be computed at $4.50 per linear foot.* Where special routing of the service lateral is required by the customer, the $4.50 per foot charge will apply to the route of the line as installed.

Where the electric service connection is installed jointly with the gas service line, the per foot charge for all footage, as measured, shall be reduced by 25 cents per foot.

(Continued on Sheet No. C-38.00)

(Continued From Sheet No. C-45.00)

C10. RENEWABLE ENERGY PLAN (REP) (Contd)

C10.2 Green Generation Program (Contd)

D. Customer Participation (Contd)

In the event the Green Generation Program is oversubscribed, the customer's name will be maintained on a Company list in the order under which they were received. The customer will be enrolled on a first-come, first-served basis for Green Generation Program Payment Options 1, 2 and 3. A customer electing Green Generation Program Payment Option 4 is subject to advance Company approval based on the availability of Green Generation Program Participation Certificates. Customers participating in Payment Options 1, 2 and 3 shall have priority for available Green Generation Program Participation Certificates. In all events, the Company reserves the right to reasonably prioritize customer participation based on economic, financial, operational, legal or other considerations.

A Green Generation Program participating customer relinquishes any rights to market or sell Green Tags or Renewable Energy Certificates (RECs) associated with the customer's participation in the Green Generation Program under this tariff. There is no provision to provide Green Tag certificates or RECs to participating customers under this tariff.

The Company may secure a third-party marketer to assist in marketing the Green Generation Program, soliciting customer and/or performing other functions on behalf of the Company. The contracted third-party marketer may contact the Company's customers directly. Under this condition, the Company would provide the contracted third-party marketer with limited customer information necessary for the sole purpose of promoting and administering the Green Generation Program on behalf of the Company. The Company will require any third-party marketer to hold customer information confidential and restrict its use to only that as authorized by the Company.

E. Payment Options and Pricing

Customers may participate in the Green Generation Program by voluntarily enrolling in a Green Generation Program payment option. In addition to the prices under the appropriate Rate Schedule, a customer who has agreed to participate in the Green Generation Program shall elect one of the following payment options:

Payment Option 1

Payment Option 1 allows customers to match 100% of their monthly total energy consumed with an equal amount of the renewable resource premium available under this program. Customers who elect to participate at the less than 15,000 kWh per month level shall pay a $0.01 per kWh renewable resource premium applicable to an amount equal to 100% of the customer's total monthly energy consumed.

Customers who elect to participate at the equal to or greater than 15,000 kWh per month level shall pay a $0.0085 per kWh renewable resource premium applicable to an amount equal to 100% of the customer's total monthly energy consumed. The minimum amount of the resource premium applicable is 15,000 kWh in any single billing month. *Customers desiring to aggregate energy consumed from multiple service accounts in order to participate at a level greater than 15,000 kWh shall be permitted to do so.*

After a customer elects to take service under Payment Option 1, the customer shall be permitted to change the established level of participation after 12 months have elapsed and 60 days notice has been given to the Company.

Payment Option 2

The customer may purchase Green Generation Program Participation Certificates in the amount of $1.50 per certificate per month. Each certificate shall represent 150 kWh of renewable electric energy procured by the Company in the Green Generation Program. Customers may purchase any number of Green Generation Program Certificates. In the event the amount of energy represented in the customer's Green Generation Program Participation Certificate exceeds the customer's actual kWh consumption for the billing period, no reconciliation shall be made on the customer's billing. If the amount of energy represented by the customer's selected Green Generation Program Participation Certificate exceeds the customer's actual kWh consumption for three consecutive billing periods, the customer may modify the number of Green Generation Program Participation Certificates selected.

(Continued on Sheet No. C-46.10)

SECTION D
RATE SCHEDULES

GENERAL TERMS AND CONDITIONS OF THE RATE SCHEDULES

A. Bills for utility service are subject to Michigan State Sales Tax. Customers may file a request with the Company for partial or total exemption from the application of sales tax in accordance with the laws of the State of Michigan and the rules of the Michigan State Department of Treasury.

B. Bills shall be increased within the limits of political subdivisions which levy special taxes, license fees or rentals against the Company's property, or its operation, or the production and/or sale of electric energy, to offset such special charges and thereby prevent other customers from being compelled to share such local increases.

C. Bills shall be increased to offset any new or increased specific tax or excise imposed by any governmental authority upon the Company's generation or sale of electrical energy.

D. A customer that commences service under any of the Company's Rate Schedules thereby agrees to abide by all of the applicable Rules and Regulations contained in this Rate Book for Electric Service.

E. Full Service Customers, applicants for service, or operators with generating facilities on or after June 8, 2012 are required to take service under *the Self-Generation Provision (SG) or* General Service Self Generation Rate GSG-2.

F. Full Service Customers shall not participate in any regional transmission organization wholesale market program until the Michigan Public Service Commission issues an order authorizing participation.

SURCHARGES

Rate Schedule	Renewable Energy Plan Surcharge (Case No U-17301) Effective beginning the July 2014 Bill Month[5]	Energy Efficiency Electric Program Surcharge (Case No. U-17351) Effective beginning the January 2014 Bill Month[3]	Energy Efficiency Self-Directed Customer Surcharge (Case No. U-17351) Effective beginning the January 2014 Bill Month[2]
Residential Rates	$0.00 /billing meter	$0.002830/kWh	NA
Rate GS and GSD [1]			
Tier 1: 0 – 1,250 kWh/mo.	$0.00 /billing meter	$ 1.63 /billing meter	$0.08 /billing meter
Tier 2: 1,251 – 5,000 kWh/mo.	0.00 /billing meter	8.89 /billing meter	0.42 /billing meter
Tier 3: 5,001 – 30,000 kWh/mo.	0.00 /billing meter	53.90 /billing meter	2.54 /billing meter
Tier 4: 30,001 – 50,000 kWh/mo.	0.00 /billing meter	53.90 /billing meter	2.54 /billing meter
Tier 5: > 50,000 kWh/mo.	0.00 /billing meter	53.90 /billing meter	2.54 /billing meter
Rate GP, GPD, GPTU and *EIP* [1]			
Tier 1: 0 – 5,000 kWh/mo.	$0.00 /billing meter	$ 3.38 /billing meter	$0.16 /billing meter
Tier 2: 5,001 – 10,000 kWh/mo.	0.00 /billing meter	24.86 /billing meter	1.18 /billing meter
Tier 3: 10,001 – 30,000 kWh/mo.	0.00 /billing meter	62.14 /billing meter	2.95 /billing meter
Tier 4: 30,001 – 50,000 kWh/mo.	0.00 /billing meter	149.06 /billing meter	7.04 /billing meter
Tier 5: > 50,000 kWh/mo.	0.00 /billing meter	714.18 /billing meter	31.88 /billing meter
Rate GSG-2	NA	NA[4]	NA
Rate GML[6]			
Tier 1: 0 – 1,250 kWh/mo.	$0.00 /billing meter	NA	NA
Tier 2: 1,251 – 5,000 kWh/mo.	0.00 /billing meter	NA	NA
Tier 3: >5,000 kWh/mo.	0.00 /billing meter	NA	NA
Rate GUL[6]	0.00 /luminaire	NA	NA
Rate GU-XL[6]	0.00 /luminaire	NA	NA
Rate GU			
Tier 1: 0 – 1,250 kWh/mo.	0.00 /billed account	NA	NA
Tier 2: 1,251 – 5,000 kWh/mo.	0.00 /billed account	NA	NA
Tier 3: >5,000 kWh/mo.	0.00 /billed account	NA	NA
Rate PA	NA	NA	NA
Rate ROA-R, ROA-S, ROA-P	NA	As in Delivery Rate Schedule	As in Delivery Rate Schedule

All Surcharges shall be applied on a monthly basis. The customer's consumption will be reviewed annually in the January bill month. Following the annual review, the customer may be subsequently moved to the Surcharge level for their applicable rate for the next billing period based on the customer's average consumption for the previous year. In situations where no historical consumption is available, the monthly Surcharge level will be based on the lowest consumption category for the secondary rate schedules or the lowest consumption category for primary rate schedules. No retroactive adjustment will be made due to the application of the REP or EE Surcharges associated with increases or decreases in consumption.

(1) Municipal Pumping customers shall be excluded from the Renewable Energy Plan Surcharge.

(2) An eligible customer who files and implements a self-directed plan in compliance with Rule C12 is required to pay the Energy Efficiency Self-Directed Program Surcharge.

(3) An Energy Efficiency Program Surcharge will be in effect for the period of the June 2009 Bill Month through the December 2015 Bill Month. The amount may vary during specific months as authorized by the Michigan Public Service Commission. Applicable cases include Case Nos. U-15805, U-16302, U-16303, U-16412, U-16670, U-16736, U-17281 and U-17351. The Surcharge for the period of the January 2014 Bill Month through the December 2014 Bill Month includes a financial incentive award approved by the Michigan Public Service Commission in Case No. U-17281. The Company will file a new tariff sheet to reflect the change in surcharges once the financial incentive recovery period has been completed.

(4) Rate GSG-2 Customers are eligible to opt-in to the Energy Efficiency Electric Program Surcharge for a two year pilot program beginning with the June 2012 bill month. A GSG-2 customer electing to participate in the Energy Efficiency Electric Program will be charged the GPD, Tier 5: > 50,000 kWh/mo rate of $714.18 per billing meter per month.

(5) The amount may vary during specific months as authorized by the Michigan Public Service Commission. Applicable cases include Case Nos. U-15805, U-16543, U-16581 and U-17301.

(6) Customer-Owned lighting fixtures served on Rate GML, GUL and Rate GU-XL are eligible to opt-in to the Energy Efficiency Program Surcharge. A GML, GUL or GU-XL customer electing to participate in the Energy Efficiency Electric Program will be charged the applicable surcharge as shown for Rate GS and GSD or Rate GP, GPD, GPTU and *EIP*, as applicable, per participating account per month.

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Consumers Energy Company **Sheet No. D-3.00**

SURCHARGES

Rate Schedule	Low-Income Energy Assistance Fund Surcharge (Case No. U-17377) Effective beginning with the September 2015 Bill Month
Rate RS[(1)]	$0.98 /billing meter
Rate RT[(1)]	0.98 /billing meter
Rate REV-1[(1)]	0.98 /billing meter
Rate REV-2[(1)]	NA
Rate GS	0.98 /billing meter
Rate GSD	0.98 /billing meter
Rate GP	0.98 /billing meter
Rate GPD	0.98 /billing meter
Rate GPTU	0.98 /billing meter
Rate *EIP*	0.98 /billing meter
Rate GSG-2	0.98 /billing meter
Rate GML	0.98 /billing meter
Rate GUL	NA
Rate GU-XL	NA
Rate GU	NA
Rate PA	NA
Rate ROA-R	0.98 /billing meter
Rate ROA-S	0.98 /billing meter
Rate ROA-P	0.98 /billing meter

[(1)]The Low Income Energy Assistance Fund Surcharge, authorized by 2013 PA 295 and the July 23, 2015 Order in Case No. U-17377, shall be applied to one residential meter per residential site.

POWER PLANT SECURITIZATION CHARGES

The actual Power Plant Securitization Charge is authorized pursuant to Rule C9.2, Power Plant Securitization Charges, Initial Implementation and True-up Methodology. The Power Plant Securitization Charge and the Power Plant Bill Credit are billed to all full service customers, shown in the rate schedules identified below, based upon usage. These charges shall be shown separately on the customer's bill.

The actual Power Plant Securitization Charge and Power Plant Bill Credit applied to customers' bills are as follows:

Rate Schedule	**Power Plant Securitization Charge (Case No. U-17473) Effective beginning with the August 2014 Billing Month**	**Power Plant Bill Credit (Case No. U-17473) Effective beginning with the August 2014 Billing Month**
Rate RS	$0.001187/kWh	$(0.001903)/kWh
Rate RT	0.001187/kWh	(0.001595)/kWh
Rate REV-1	0.001187/kWh	(0.001399)/kWh
Rate REV-2	0.001187/kWh	(0.001399)/kWh
Rate GS	0.001186/kWh	(0.002007)/kWh
Rate GSD	0.001186/kWh	(0.001875)/kWh
Rate GP		
CVL 1	0.000927/kWh	(0.001537)/kWh
CVL 2	0.000927/kWh	(0.001623)/kWh
CVL 3	0.000927/kWh	(0.001802)/kWh
Rates GPD, GPTU, *EIP* and GSG-2		
CVL 1	0.000927/kWh	(0.001326)/kWh
CVL 2	0.000927/kWh	(0.001447)/kWh
CVL 3	0.000927/kWh	(0.001664)/kWh
Rate GML	0.000566/kWh	(0.000924)/kWh
Rate GUL	0.000566/kWh	(0.000924)/kWh
Rate GU-XL	0.000566/kWh	(0.000924)/kWh
Rate GU	0.000566/kWh	(0.000924)/kWh
Rate PA	NA	NA
Rate ROA-R(1)	NA	NA
Rate ROA-S(1)	NA	NA
Rate ROA-P(1)	NA	NA

(1) 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 will pay the Power Plant Securitization Charges applicable to the customer's otherwise applicable Company Full Service Rate Schedule.

RATE CATEGORIES AND PROVISIONS

Description	Full Service	Retail Open Access
RESIDENTIAL SERVICE SECONDARY RATE RS		
Residential	1000	2000
<u>Provisions</u>		
Residential With Income Assistance (RIA) *	Applicable	Applicable
Residential With Senior Citizen (RSC) *	Applicable	Applicable
Residential With Direct Load Management (DLM)	1005	Not Applicable
Residential With Dynamic Pricing (RDP) **	1007	Not Applicable
Residential With Dynamic Pricing Rebate (RDPR) **	1008	Applicable
*Residential With Self-Generation (SG)***	*1700*	*Not Applicable*
Net Metering Program	Applicable	Applicable
Green Generation Program	Applicable	Not Applicable
RESIDENTIAL SERVICE TIME-OF-DAY SECONDARY RATE RT		
Residential Time-of-Day	1010	2010
<u>Provisions</u>		
Residential Time-of-Day With Income Assistance (RIA) *	Applicable	Applicable
Residential Time-of-Day With Senior Citizen (RSC) *	Applicable	Applicable
*Residential Time-of-Day With Self-Generation (SG)****	*1705*	*Not Applicable*
Net Metering Program	Applicable	Not Applicable
Green Generation Program	Applicable	Not Applicable
EXPERIMENTAL RESIDENTIAL PLUG-IN ELECTRIC VEHICLE CHARGING PROGRAM		
Residential Electric Vehicle Service (REV-1)	1020	Not Applicable
*Residential Electric Vehicle Service (REV-1) With Self-Generation (SG)****	*1710*	*Not Applicable*
Residential Electric Vehicle Service (REV-2)	1030	Not Applicable
Green Generation	Applicable	Not Applicable

* Provisions shall not be taken in conjunction with each other.
** Provision shall not be taken in conjunction with the Direct Load Management Provision or Net Metering Program.
**** Provision shall not be taken in conjunction with the Net Metering Program.*

(Continued on Sheet No. D-6.10)

RATE CATEGORIES AND PROVISIONS

(Continued From Sheet No. D-6.00)

Description	Full Service	Retail Open Access
GENERAL SERVICE SECONDARY RATE GS		
Commercial	1100	2100
Commercial – Temporary Construction Service	*1999*	*Not Applicable*
Industrial	1110	2110
<u>Provisions</u>		
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
Industrial With Educational Institution (GEI)	Applicable	Applicable
Commercial Direct Load Management DLM)	1118	Not Applicable
Industrial Direct Load Management (DLM)	1119	Not Applicable
Commercial With Dynamic Pricing*	1121	Not Applicable
Industrial With Dynamic Pricing*	1122	Not Applicable
*Commercial With Self-Generation (SG)***	*1715*	*Not Applicable*
*Industrial With Self-Generation (SG) ***	*1720*	*Not Applicable*
Net Metering Program	Applicable	Applicable
Green Generation Program	Applicable	Not Applicable
Non-Transmitting Meter Provision	Applicable	Applicable
GENERAL SERVICE SECONDARY DEMAND RATE GSD		
Commercial	1120	2120
Industrial	1130	2130
Commercial (100 kW Billing Demand Guarantee)	1140	2140
Industrial (100 kW Billing Demand Guarantee)	1150	2150
<u>Provisions</u>		
Commercial Resale	Applicable	Applicable
Commercial With Educational Institution (GEI)	Applicable	Applicable
Industrial With Educational Institution (GEI)	Applicable	Applicable
Commercial With Dynamic Pricing*	1156	Not Applicable
Industrial With Dynamic Pricing*	1157	Not Applicable
*Commercial With Self-Generation (SG)***	*1725*	*Not Applicable*
*Industrial With Self-Generation (SG) ***	*1730*	*Not Applicable*
*Commercial (100 kW Billing Demand Guarantee) With Self-Generation (SG)***	*1735*	*Not Applicable*
*Industrial (100 kW Billing Demand Guarantee) With Self-Generation (SG) ***	*1740*	*Not Applicable*
Net Metering Program	Applicable	Applicable
Green Generation Program	Applicable	Not Applicable
GENERAL SERVICE *PRIMARY* RATE GP		
Commercial (Customer Voltage Level 1, 2 or 3)	1200	2200
Industrial (Customer Voltage Level 1, 2 or 3)	1210	2210
<u>Provisions</u>		
Commercial (Customer Voltage Level 1, 2 or 3) Resale	Applicable	Applicable
Commercial (Customer Voltage Level 1, 2 or 3) With Educational Institution (GEI)	Applicable	Applicable
Commercial (Customer Voltage Level 1, 2 or 3) With Dynamic Pricing*	1211	Not Applicable
Industrial (Customer Voltage Level 1, 2 or 3) With Dynamic Pricing*	1212	Not Applicable
*Commercial With Self-Generation (SG)***	*1745*	*Not Applicable*
*Industrial With Self-Generation (SG) ***	*1750*	*Not Applicable*
Net Metering Program	Applicable	Applicable
Green Generation Program	Applicable	Not Applicable

* Provision shall not be taken in conjunction with the DLM Provision, GEI Provision, or the Net Metering Program.
*** Provision shall not be taken in conjunction with Dynamic Pricing or the Net Metering Program.*

(Continued on Sheet No. D-7.00)

RATE CATEGORIES AND PROVISIONS

(Continued From Sheet No. D-6.10)

Description	Full Service	Retail Open Access
GENERAL SERVICE *PRIMARY* DEMAND RATE GPD		
	1220	2220
Commercial (Customer Voltage Level 1, 2 or 3)	1230	2230
Industrial (Customer Voltage Level 1, 2 or 3)		
<u>Provisions</u>	Applicable	Applicable
Commercial (Customer Voltage Level 1, 2 or 3) Resale	Applicable	Applicable
Industrial (Customer Voltage Level 1, 2 or 3) Resale	Applicable	Applicable
Commercial (Customer Voltage Level 1, 2 or 3) With Aggregate Peak Demand (GAP)**	Applicable	Not Applicable
Industrial (Customer Voltage Level 1, 2 or 3) With Aggregate Peak Demand (GAP)**	Applicable	Not Applicable
Commercial (Customer Voltage Level 1, 2 or 3) With Educational Institution (GEI)**	Applicable	Applicable
Industrial (Customer Voltage Level 1, 2 or 3) With Educational Institution (GEI)**	Applicable	Applicable
Commercial (Customer Voltage Level 1, 2 or 3) With Interruptible (GI)	Applicable	Not Applicable
Industrial (Customer Voltage Level 1, 2 or 3) With Interruptible (GI)	Applicable	Not Applicable
*Commercial (Customer Voltage Level 1, 2 or 3) With Self-Generation (SG)****	*1755*	*Not Applicable*
*Industrial (Customer Voltage Level 1, 2 or 3) With Self-Generation (SG)****	*1760*	*Not Applicable*
Net Metering Program	Applicable	Applicable
Green Generation Program	Applicable	Not Applicable
GENERAL SERVICE PRIMARY TIME-OF-USE PILOT RATE GPTU		
Commercial (Customer Voltage Level 1, 2 or 3)	1280	Not Applicable
Industrial (Customer Voltage Level 1, 2 or 3)	1285	Not Applicable
<u>Provisions</u>		
*Commercial (Customer Voltage Level 1, 2 or 3) With Self-Generation (SG)****	*1765*	*Not Applicable*
*Industrial (Customer Voltage Level 1, 2 or 3) With Self-Generation (SG)****	*1770*	*Not Applicable*
Net Metering Program	Applicable	Not Applicable
Green Generation Program	Applicable	Not Applicable
GENERAL SERVICE *ENERGY INTENSIVE* PRIMARY RATE *EIP*		
Industrial (Customer Voltage Level 1, 2, or 3)	1250	Not Applicable

* Provisions shall not be taken in conjunction with the, DLM provision, GEI provision, or the Net Metering Program.
** Provisions shall not be taken in conjunction with each other.
**** Provision shall not be taken in conjunction with the DLM provision or the Net Metering Program.*

(Continued on Sheet No. D-7.10)

M.P.S.C. No. 13 - Electric
Consumers Energy Company **Sheet No. D-7.10**

RATE CATEGORIES AND PROVISIONS

(Continued From Sheet No. D-7.00)

Description	Full Service	Retail Open Access
EXPERIMENTAL ADVANCED RENEWABLE PROGRAM AR		
Residential	1015	2015
Commercial – Secondary Delivery, Rate GS	1105	2105
Industrial – Secondary Delivery, Rate GS	1115	2115
Commercial – Secondary Delivery, Rate GSD	1125	2125
Industrial – Secondary Delivery, Rate GSD	1135	2135
Commercial – Primary Delivery, Rate GP	1205	2205
Industrial – Primary Delivery, Rate GP	1215	2215
Commercial – Primary Delivery, Rate GPD	1225	2225
Industrial – Primary Delivery, Rate GPD	1235	2235
GENERAL SERVICE SELF GENERATION RATE GSG-2		
Commercial – Primary Service	1320	Not Applicable
Commercial (Customer Voltage Service Level 1, 2 or 3) – Primary Service 100 kW or less	1325	Not Applicable
Commercial (Customer Voltage Service Level 1, 2 or 3) – Primary Service over 100kW	1330	Not Applicable
Industrial – Primary Service	1340	Not Applicable
Industrial (Customer Voltage Service Level 1, 2 or 3) – Primary Service 100 kW or less	1345	Not Applicable
Industrial (Customer Voltage Service Level 1, 2 or 3) – Primary Service over 100kW	1350	Not Applicable
Provisions		
Green Generation Program	Applicable	Not Applicable

(Continued on Sheet No. D-8.10)

RATE CATEGORIES AND PROVISIONS

(Continued From Sheet No. D-7.10)

Description	Full Service	Retail Open Access
GENERAL SERVICE METERED LIGHTING RATE GML		
Commercial - Secondary Metered Service	1400	Not Applicable
Commercial - Primary Metered Service	1405	Not Applicable
Provisions		
Net Metering Program	Applicable	Applicable
Green Generation Program	Applicable	Not Applicable
GENERAL SERVICE UNMETERED LIGHTING RATE GUL		
Commercial - Customer-Owned Incandescent Luminaire	1410	Not Applicable
Commercial - Customer-Owned Mercury Vapor Luminaire	1415	Not Applicable
Commercial - Customer-Owned High-Pressure Sodium Luminaire	1420	Not Applicable
Commercial - Customer-Owned Metal Halide Luminaire	1425	Not Applicable
Commercial - Company-Owned Incandescent Luminaire	1430	Not Applicable
Commercial - Company-Owned Fluorescent Luminaire	1435	Not Applicable
Commercial - Company-Owned Mercury Vapor Luminaire	1440	Not Applicable
Commercial - Company-Owned High-Pressure Sodium Luminaire	1445	Not Applicable
Commercial - Company-Owned Metal Halide Luminaire	1450	Not Applicable
Commercial - Outdoor Area Lighting	1455	Not Applicable
Industrial - Outdoor Area Lighting	1460	Not Applicable
Provisions		
Green Generation Program	Applicable	Not Applicable
GENERAL UNMETERED EXPERIMENTAL LIGHTING RATE GU-XL		
Commercial - Company-Owned Secondary Service, XL	1600	Not Applicable
Commercial - Customer-Owned Secondary Service, XL	1650	Not Applicable
Provisions		
Green Generation Program	Applicable	Not Applicable
GENERAL SERVICE UNMETERED RATE GU		
Commercial - Secondary Service	1500	Not Applicable
Provisions		
Commercial - Lighting Service	Applicable	Not Applicable
Commercial - Traffic Lighting Service	Applicable	Not Applicable
Commercial - Cable Television (CATV) Service	Applicable	Not Applicable
Commercial - Wireless Access Service	Applicable	Not Applicable
Commercial - Security Camera Service	Applicable	Not Applicable
Green Generation Program	Applicable	Not Applicable
GENERAL SERVICE SPECIAL CONTRACTS		
Commercial	1150	Not Applicable

RESIDENTIAL SERVICE SECONDARY RATE RS

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 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:	$*0.091101*	per kWh for the first 600 kWh per month during the billing months of June-September
	$*0.131308*	per kWh for all kWh over 600 kWh per month during the billing months of June-September
	$*0.091101*	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-4.00.

Delivery Charges: These charges are applicable to Full Service and Retail Open Access customers.

System Access Charge:	$7.00	per customer per month
Distribution Charge:	$*0.045463*	per kWh for all kWh

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-3.10 and the Securitization Charges shown on Sheet Nos. D-5.00 and D-5.10.

(Continued on Sheet No. D-10.00)

RESIDENTIAL SERVICE SECONDARY RATE RS

(Continued From Sheet No. D-10.00)

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: $(3.50) per customer per month

This credit shall not be taken in conjunction with a credit for the Income Assistance Service Provision (RIA).

Self-Generation Provision (SG):

As of June 8, 2012, this provision may be required for any Full Service Customer with a generating installation less than 550 kW operating in parallel with the Company's system, which may employ cogeneration or small power production technology.

All facilities must meet the Parallel Operation Requirements set forth in Rule C1.6 B. The Company shall own, operate and maintain all metering and auxiliary devices (including telecommunication links) at the customer's expense. Meters furnished, installed and maintained by the Company shall meter generation equipment for customers that sell energy to the Company. No refund shall be made for any customer contribution required.

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) Secondary Voltage or Primary Voltage service. The Company will determine the particular nature of the voltage in each case.

Self-generation customers requiring Company delivery service for any portion of the load that has been self-generated will be charged as described in the Delivery Charges section of this Rate Schedule.

Sales of Self-Generated Energy to the Company:

A customer who meets the Federal Energy Regulatory Commission's (FERC) criteria for a Qualifying Facility may elect to sell energy to the Company. 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.

Where the customer elects to sell energy to the Company, an Interval Data Meter (IDM)or other applicable meter is required for their generator. 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.

Administrative Cost Charge: *$0.0010 per kWh purchased for generation installations with a capacity of 100 kW or less.*

Energy Purchase:

An energy purchase by the Company shall be bought at the Midwest Independent Transmission System Operator's (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) less $0.005/kWh. The Company may discontinue purchases during system emergencies, maintenance and other operational circumstances.

Direct Load Management Pilot (DLM):

A customer in a single family residence who is taking service from the Company may be eligible to participate in the Company's voluntary electric central air conditioning, central heat pump, or other qualifying electric equipment Load Management Pilot. Customer eligibility to participate in this pilot is determined solely by the Company.The customer must be located within an area in which Advanced Metering Infrastructure (AMI) is deployed and fully operational for purposes of this pilot. The Company will accept a customer's central air conditioning , central heat pump, and other qualifying electric equipment under this pilot 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 provision 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. 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.

(Continued on Sheet No. D-11.10)

RESIDENTIAL SERVICE SECONDARY RATE RS

(Continued From Sheet No. D-11.00)

Monthly Rate: (Contd)

Direct Load Management Pilot (DLM): (Contd)

The Company reserves the right to specify the term or duration of the pilot. The participating customer may elect to terminate service for any reason by providing the Company with thirty days' notice prior to the customer's next billing cycle. The customer's enrollment shall be terminated if the voluntary pilot 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 the regional grid operator.*

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 *Direct Load Management* 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 Direct Load Management Pilot.

The monthly **credit** for the Direct Load Management Pilot shall be applied as follows:

Power Supply Charges: These charges are applicable to Full Service Customers.

Direct Load Management Credit: $(*0.040207)* per kWh for all kWh over 600 kWh during the billing months of June-September

Residential Dynamic Pricing *Rate*:

The Dynamic Pricing is a voluntary *rate* available to Full Service residential customers taking service under the Company's RS tariff and who have, or are selected to have, the required metering equipment and infrastructure installed. Customer eligibility to participate in this *rate* is determined solely by the Company. The Company will furnish, install, maintain and own the required equipment at the customers' premises at the Company's expense. *At the sole discretion of the Company, customers may be allowed to furnish, install and maintain the equipment at the customer's expense.* Equipment *and* installations must conform to the Company's specifications. By enrolling in the *rate*, the customer agrees to participate in surveys and understands that the metering data will be used for evaluation purposes.

The participating customer may elect to terminate service for any reason giving the Company thirty days' notice prior to the customer's next billing cycle. The customer's enrollment shall be terminated if the *rate* ceases or for any reasons as provided for in Rule C1.3, Use of Service.

Deployment of the Residential Dynamic Pricing *Rate* is at the sole discretion of the Company and is dependent upon installation of advanced metering infrastructure and supporting critical systems.

This *rate* shall not be taken in conjunction with any other Demand Response Program or Net Metering.

The customer may choose either the Residential Dynamic Pricing or the Residential Dynamic Pricing Rebate.

(Continued on Sheet No. D-11.20)

M.P.S.C. No. 13 - Electric
Consumers Energy Company **Sheet No. D-11.20**

RESIDENTIAL SERVICE SECONDARY RATE RS

(Continued From Sheet No. 11.10)

Monthly Rate: (Contd)

Residential Dynamic Pricing *Rate*: (Contd)

Residential Dynamic Pricing (RDP)

Customers placed under the RDP will be charged the power supply rates listed below in place of the standard RS tariff power supply rates for the summer months of June through September. Customers are able to manage electric costs by either reducing load during high cost pricing periods or shifting load from high cost pricing periods to lower cost pricing periods. The Company may select a subset of the RDP customers to be provided with additional technology at the Company's expense in order to measure the response difference between customers with and without the additional technology.

The Company may call up to eight critical peak events in the summer months of June through September, excluding weekends and holidays, for the on-peak hours of 2:00 PM to 6:00 PM. During a critical peak event, customers under the RDP will be charged the critical peak price in the place of the On-Peak power supply charge. Customers will be notified the day before a critical peak event is expected to occur. Receipt of such notice is the responsibility of the participating customer.

Power Supply Charges: These charges are applicable to Full Service Customers.

Summer Energy Charge

	$/kWh	
Off-Peak	$*0.059344*	for the hours of 12:00 AM to 7:00 AM and 11:00 PM to 12:00 AM
Mid-Peak	$*0.093100*	for the hours of 7:00 AM to 2:00 PM and 6:00 PM to 11:00 PM
On-Peak	$*0.117705*	for the hours of 2:00 PM to 6:00 PM
Critical Peak Pricing	$*0.950000*	for the hours of 2:00 PM to 6:00 PM during a critical peak event day

Residential Critical Peak Rebate (RDPR)

Customers placed under the RDPR will be charged the power supply prices listed below in place of the standard RS tariff power supply rates for the summer months of June through September. Customers can manage their electric costs by either reducing load during the high cost pricing periods or shifting load from high cost pricing periods to lower cost pricing periods. The Company will provide a subset of the RDPR customers with additional technology at the Company's expense in order to measure the response difference between customers with and without the additional technology.

(Continued on Sheet No. D-11.30)

M.P.S.C. No. 13 - Electric
Consumers Energy Company **Sheet No. D-11.30**

RESIDENTIAL SERVICE SECONDARY RATE RS
(Continued From Sheet No. D-11.20)

Monthly Rate: (Contd)

Residential Dynamic Pricing *Rate*: (Contd)

Residential Dynamic Pricing Rebate (RDPR) (Contd)

The Company may call up to eight critical peak events in the summer months of June through September, excluding weekends and holidays, for the on-peak hours of 2:00 PM to 6:00 PM. During a critical peak event, customers under the RDPR will be credited the critical peak rebate for incremental energy reductions . The customer's incremental energy reduction will be the difference between a customer's baseline hourly consumption and their recorded hourly consumption during a critical peak event. The customer's baseline consumption is the hourly average consumption from the prior five non-event business days. Customers will be notified the day before a critical peak event is expected to occur. Receipt of such notice is the responsibility of the participating customer.

Power Supply Charges: These charges are applicable to Full Service Customers.

Summer Energy Charge

		$/kWh
Off-Peak	$*0.071271*	for the hours of 12:00 AM to 7:00 AM and 11:00 PM to 12:00 AM
Mid-Peak	$*0.111813*	for the hours of 7:00 AM to 2:00 PM and 6:00 PM to 11:00 PM
On-Peak	$*0.141363*	for the hours of 2:00 PM to 6:00 PM
Critical Peak Pricing	$(*0.950000)*	for the hours of 2:00 PM to 6:00 PM during a critical peak event day

(Continued on Sheet No. D-12.00)

RESIDENTIAL SERVICE SECONDARY RATE RS

(Continued From Sheet No. D-11.30)

Monthly Rate: (Contd)

Net Metering Program:

The Net Metering Program is available to any eligible customer as described in Rule C11., 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.B, Net Metering Definitions.

A customer who participates in the Net Metering Program is subject to the provisions contained in Rule C11., 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.

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 applicable REP Surcharge and EE Surcharge shown on Sheet D-2.10, *the LIEAF Surcharge on Sheet D-3.00* and the System Access Charge included in the rate, adjusted for any service provision credit.

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 Gas Residential Service, R 460.122, Allowable Charges.

Term and Form of Contract:

Service under this rate shall not require a written contract except for the Green Generation Program participants.

EXPERIMENTAL RESIDENTIAL PLUG-IN ELECTRIC VEHICLE CHARGING PROGRAM

Availability:

The Experimental Residential Plug-In Electric Vehicle Charging Program is a voluntary pilot available to Full Service residential customers. Upon enrollment of the customer in the program, the customer may take service under one of the following options as applicable:

Option 1 - Residential Home and Plug-in Electric Vehicle Time-of-Day Rate (REV-1) – Level 1 or Level 2 Charging of an electric vehicle combined with household electric usage such as space conditioning, cooking, water heating, refrigeration, clothes drying, incineration or lighting based upon on-peak, mid-peak and off-peak periods and through a single meter.

Option 2 - Residential Plug-In Electric Vehicle Only Time-of-Day Rate (REV-2) – Level 2 Charging of the electric vehicle based upon on-peak, mid-peak and off-peak periods through a separate meter. Electric usage for the household will be billed under the RS or RT Rate Schedule.

"Level 1 Charging" is defined as voltage connection of 120 volts and a maximum load of 12 amperes or 1.4 kVA.

"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.

"Electric Vehicle Supply Equipment (EVSE)" is defined as the conductors, including the ungrounded, grounded and equipment grounding conductors, the electric vehicle connectors, attachment plugs, and all other fittings, devices, power outlets, or apparatus installed specifically for the purpose of delivering energy from the premise wiring to the electric vehicle.

Vehicles shall be registered and operable on public highways in the State of Michigan to qualify for this rate. Low-speed electric vehicles including golf carts are not eligible to take service under this rate 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 program.

The total connected load of the home including the electric vehicle charging shall not exceed 10 kW, without the specific consent of the Company.

Customers shall not back-feed or transmit stored energy from the electric vehicle's battery to the Company's distribution system.

Subject to the limitation of this pilot program, the first 2,500 participating customers through December 31, 2014 may be reimbursed up to $2,500 toward the purchase of Company approved Electric Vehicle Supply Equipment (EVSE) if not otherwise provided, installation of the EVSE and a separately metered circuit as applicable. Installation must conform to Company specifications.

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.

Monthly Rate:

Option 1 REV-1:

Power Supply Charges: These charges are applicable to Full Service customers.

Energy Charge:

	$/kWh	
Off-Peak – Summer	$*0.059474*	per kWh for all Off-Peak kWh during the billing months of June-September
Mid-Peak – Summer	$*0.093397*	per kWh for all Mid-Peak kWh during the billing months of June-September
On-Peak – Summer	$*0.124632*	per kWh for all On-Peak kWh during the billing months of June-September
Off-Peak – Winter	$*0.059474*	per kWh for all Off-Peak kWh during the billing months of October-May
On-Peak – Winter	$*0.095024*	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-4.00.

(Continued on Sheet No. D-13.20)

EXPERIMENTAL RESIDENTIAL PLUG-IN ELECTRIC VEHICLE CHARGING PROGRAM
(Continued from Sheet No. D-13.10)

Monthly Rate (Continued):

Delivery Charges: These charges are applicable to Full Service customers.

System Access Charge:	$7.00	per customer per month
Distribution Charge:	$*0.045463*	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-3.10 and the Securitization Charges shown on Sheet Nos. D-5.00 and D-5.10.

General Terms:

These rates are subject to all general terms and conditions shown on Sheet No. D-1.00.

Self-Generation Provision (SG):

As of June 8, 2012, this provision may be required for any Full Service Customer with a generating installation less than 550 kW operating in parallel with the Company's system, which may employ cogeneration or small power production technology.

All facilities must meet the Parallel Operation Requirements set forth in Rule C1.6 B. The Company shall own, operate and maintain all metering and auxiliary devices (including telecommunication links) at the customer's expense. Meters furnished, installed and maintained by the Company shall meter generation equipment for customers that sell energy to the Company. No refund shall be made for any customer contribution required.

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) Secondary Voltage or Primary Voltage service. The Company will determine the particular nature of the voltage in each case.

Self-generation customers requiring Company delivery service for any portion of the load that has been self-generated will be charged as described in the Delivery Charges section of this Rate Schedule.

Sales of Self-Generated Energy to the Company:

A customer who meets the Federal Energy Regulatory Commission's (FERC) criteria for a Qualifying Facility may elect to sell energy to the Company. 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.

Where the customer elects to sell energy to the Company, an Interval Data Meter (IDM) or other applicable meter is required for their generator. 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.

Administrative Cost Charge: *$0.0010 per kWh purchased for generation installations with a capacity of 100 kW or less.*

Energy Purchase:

An energy purchase by the Company shall be bought at the Midwest Independent Transmission System Operator's (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) less $0.005/kWh. The Company may discontinue purchases during system emergencies, maintenance and other operational circumstance.

Option 2 – REV-2:

Power Supply Charges: These charges are applicable to Full Service customers.

Energy Charge:

	$/kWh
Off-Peak – Summer	$*0.059474* per kWh for all Off-Peak kWh during the billing months of June-September
Mid-Peak – Summer	$*0.093397* per kWh for all Mid-Peak kWh during the billing months of June-September
On-Peak – Summer	$*0.124632* per kWh for all On-Peak kWh during the billing months of June-September
Off-Peak – Winter	$*0.059474* per kWh for all Off-Peak kWh during the billing months of October-May

On-Peak – Winter $*0.095024* 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-4.00.

Delivery Charges: These charges are applicable to Full Service customers.

Distribution Charge: $*0.045463* for all kWh

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-3.10 and the Securitization Charges shown on Sheet Nos. D-5.00 and D-5.10. The REP Surcharge shown on Sheet No. D-2.10 shall not apply.

General Terms:

These rates are subject to all general terms and conditions shown on Sheet No. D-1.00.

(Continued on Sheet No. D-13.30)

RESIDENTIAL SERVICE TIME-OF-DAY SECONDARY RATE RT

Availability:

Subject to any restrictions, this rate is available to any residential customer desiring electric service who chooses to have their electric consumption metered based upon on-peak and off-peak periods. In addition, this rate is available to customers desiring electric service for electric vehicle battery charging where such service is in addition to all other household requirements. Battery charging service is limited to four-wheel vehicles licensed for operation on public streets and highways. 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.

Service under this rate is limited to 10,000 customers.

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.

On-Peak Energy Charge:	$*0.119176*	per kWh for all kWh during the billing months of June-September
Off-Peak Energy Charge:	$*0.074522*	per kWh for all kWh during the billing months of June-September
On-Peak Energy Charge:	$*0.094450*	per kWh for all kWh during the billing months of October-May
Off-Peak Energy Charge:	$*0.081537*	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-4.00.

Delivery Charges: These charges are applicable to Full Service and Retail Open Access Customers.

System Access Charge:	$7.00	per customer per month
Distribution Charge:	$*0.045463*	per kWh for all kWh

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-3.10 and the Securitization Charges shown on Sheet Nos. D-5.00 and D-5.10.

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 if the requirements under Rule B2, Consumer Standards and Billing Practices for Electric and Gas Residential Customers, R 460.102 are met. 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:	$(7.00)	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-15.00)

RESIDENTIAL SERVICE TIME-OF-DAY SECONDARY RATE RT
(Continued from Sheet No. D-14.00)

Monthly Rate: (Contd)

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 and Retail Open Access Customers.

Senior Citizen Credit:	$(3.50)	per customer per month

This credit shall not be taken in conjunction with a credit for the Income Assistance Service Provision (RIA).

Self-Generation Provision (SG):

As of June 8, 2012, this provision may be required for any Full Service Customer with a generating installation less than 550 kW operating in parallel with the Company's system, which may employ cogeneration or small power production technology.

All facilities must meet the Parallel Operation Requirements set forth in Rule C1.6 B. The Company shall own, operate and maintain all metering and auxiliary devices (including telecommunication links) at the customer's expense. Meters furnished, installed and maintained by the Company shall meter generation equipment for customers that sell energy to the Company. No refund shall be made for any customer contribution required.

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) Secondary Voltage or Primary Voltage service. The Company will determine the particular nature of the voltage in each case.

Self-generation customers requiring Company delivery service for any portion of the load that has been self-generated will be charged as described in the Delivery Charges section of this Rate Schedule.

Sales of Self-Generated Energy to the Company:

A customer who meets the Federal Energy Regulatory Commission's (FERC) criteria for a Qualifying Facility may elect to sell energy to the Company. 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.

Where the customer elects to sell energy to the Company, an Interval Data Meter (IDM) or other applicable meter is required for their generator. 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.

Administrative Cost Charge: *$0.0010 per kWh purchased for generation installations with a capacity of 100 kW or less.*

Energy Purchase:

An energy purchase by the Company shall be bought at the Midwest Independent Transmission System Operator's (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) less $0.005/kWh. The Company may discontinue purchases during system emergencies, maintenance and other operational circumstance.

(Continued on Sheet No. D-16.00)

RESIDENTIAL SERVICE TIME-OF-DAY SECONDARY RATE RT

(Continued from Sheet No. D-15.00)

Monthly Rate: (Contd)

Net Metering Program:

The Net Metering Program is available to any eligible customer as described in Rule C11., 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.B, Net Metering Definitions.

A customer who participates in the Net Metering Program is subject to the provisions contained in Rule C11, 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.

General Terms:

This rate is subject to all general terms and conditions shown on Sheet No. D-1.00.

Minimum Charge:

The applicable REP Surcharge and EE Surcharge shown on Sheet D-2.10*, the LIEAF Surcharge on Sheet D-3.00* and the System Access Charge included in the rate, adjusted for any service provision credit.

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 Gas Residential Service, R 460.122, Allowable Charges.

Schedule of On-Peak and Off-Peak Hours:

The following schedule shall apply Monday through Friday:

(1) On-Peak Hours: 11:00 AM to 7:00 PM
(2) Off-Peak Hours: 7:00 PM to 11:00 AM

Term and Form of Contract:

Service under this rate shall not require a written contract.

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) self-generation service, (v) resale for lighting service, or (vi) 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: $*0.098697* per kWh for all kWh during the billing months of June-September
$*0.091222* 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-4.00.

Delivery Charges: These charges are applicable to Full Service and Retail Open Access (ROA) Customers.

System Access Charge: $20.00 per customer per month

Distribution Charge: $*0.042445* per kWh for all kWh

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-3.10 and the Securitization Charges shown on Sheet Nos. D-5.00 and D-5.10.

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-19.00)

GENERAL SERVICE SECONDARY RATE GS

(Continued From Sheet No. D-18.00)

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.

Educational Institution Credit: $*(0.000939)* 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 Provision (SG):

As of June 8, 2012, this provision May be required for any Full Service Customer with a generating installation less than 550 kW operating in parallel with the Company’s system, which may employ cogeneration or small power production technology.

All facilities must meet the Parallel Operation Requirements set forth in Rule C1.6 B. The Company shall own, operate and maintain all metering and auxiliary devices (including telecommunication links) at the customer's expense. Meters furnished, installed and maintained by the Company shall meter generation equipment for customers that sell energy to the Company. No refund shall be made for any customer contribution required.

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) Secondary Voltage or Primary Voltage service. The Company will determine the particular nature of the voltage in each case.

Self-generation customers requiring Company delivery service for any portion of the load that has been self-generated will be charged as described in the Delivery Charges section of this Rate Schedule.

Sales of Self-Generated Energy to the Company:

A customer who meets the Federal Energy Regulatory Commission’s (FERC) criteria for a Qualifying Facility may elect to sell energy to the Company. 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.

Where the customer elects to sell energy to the Company, an Interval Data Meter (IDM) or other applicable meter is required for their generator. 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.

Administrative Cost Charge: *$0.0010 per kWh purchased for generation installations with a capacity of 100 kW or less.*

Energy Purchase:

An energy purchase by the Company shall be bought at the Midwest Independent Transmission System Operator's (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) less $0.005/kWh. The Company may discontinue purchases during system emergencies, maintenance and other operational circumstances.

(Continued on Sheet No. D-19.10)

GENERAL SERVICE SECONDARY RATE GS

(Continued From Sheet No. D-19.00)

Monthly Rate: (Contd)

Direct Load Management Pilot (DLM):

A General Service Secondary Rate GS customer who is taking service from the Company may be eligible to participate in the Company's voluntary electric central air conditioning, central heat pump or other qualifying electric equipment Load Management Pilot. Customer eligibility to participate in this pilot is determined solely by the Company. The customer must be located within an area in which Advanced Metering Infrastructure (AMI) is deployed and fully operational for purposes of this provision. The Company will accept a customer's electric central air conditioning, central heat pump and other qualifying electric equipment under this pilot 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 provision only if the customer is allowing Load Management of their air conditioner or heat pump unit. This provision is not open to resale customers or customers taking the GEI or GMP provisions under Rate GS. The Company will install the required equipment at the customer's premises which will allow Load Management upon signal from the Company. Such equipment shall be furnished, installed, maintained and owned by the Company at the Company's expense. *At the sole discretion of the Company, customers may be allowed to furnish, install and maintain the equipment at the customer's expense.* Equipment *and* installations must conform to the Company's specifications.

The Company reserves the right to specify the term of duration of the pilot. The participating customer may elect to terminate service for any reason by providing the Company with thirty days' notice prior to the customer's next billing cycle. The customer's enrollment shall be terminated if the voluntary pilot ceases, if the customer tampers with the control switch or the Company's equipment or for 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 the regional grid operator.*

The customer may contact the Company 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 *Direct Load Management* 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 Direct Load Management Pilot.

The monthly **credit** for the Direct Load Management Pilot shall be applied as follows:

Power Supply Charges: These charges are applicable to Full Service Customers.

Direct Load Management Credit: $*(0.040207)* per kWh for all kWh over 1,200 kWh during the billing months of June-September

Dynamic Pricing Pilot:

The Dynamic Pricing Pilot is a voluntary pilot available at the discretion of the Company to Full Service Customers taking service under the Company's GS tariff and whom have, or are selected to have, the required metering equipment and infrastructure installed. Customer eligibility to participate in this pilot is determined solely by the Company. The Company will furnish, install, maintain and own the required equipment at the customers' premises at the Company's expense for the duration of the pilot. *At the sole discretion of the Company, customers may be allowed to furnish, install and maintain the equipment at the customer's expense.* Equipment *and* installations must conform to the Company's specifications. By enrolling in the pilot, the customer agrees to participate in surveys and understands that the metering data will be used for pilot evaluation purposes. This pilot shall not be taken in conjunction with the DLM Provision, the GEI Provision or Net Metering

(Continued on Sheet No. D-20.00)

GENERAL SERVICE SECONDARY RATE GS

(Continued from Sheet No. D-19.10)

Monthly Rate: (Contd)

Dynamic Pricing Pilot: (Contd)

The Company reserves the right to specify the term of duration of the pilot. The participating customer may elect to terminate service for any reason giving the Company thirty days' notice prior to the customer's next billing cycle. The customer's enrollment shall be terminated if the voluntary pilot ceases or for any reasons as provided for in Rule C1.3, Use of Service.

Deployment of the General Service Dynamic Pricing Pilot is at the sole discretion of the Company and is contingent upon installation of advanced metering infrastructure and supporting critical systems.

Customers that choose to participate in the Dynamic Pricing Pilot will be charged the power supply prices listed below in place of the standard GS tariff power supply rates for the summer months of June through September. Customers can manage their electric costs by either reducing load during high cost pricing periods or shifting load from high cost pricing periods to lower cost pricing periods. The Company may select a subset of the Dynamic Pricing Pilot customers to be provided with additional technology at the Company's expense in order to measure the response difference between customers with and without the additional technology.

The Company may call up to eight critical peak events in the summer months of June through September, excluding weekends and holidays, for the on-peak hours of 2:00 PM to 6:00 PM. During a critical peak event, customers will be charged the critical peak price in the place of the on-peak power supply charge. Customers will be notified the day before a critical peak event is expected to occur. Receipt of such notice is the responsibility of the participating customer.

Power Supply Charges: These charges are applicable to Full Service Customers.

Summer Energy Charge

	$/kWh	
Off-Peak	$*0.058278*	for the hours of 12:00 AM to 7:00 AM and 11:00 PM to 12:00 AM
Mid-Peak	$*0.091428*	for the hours of 7:00 AM to 2:00 PM and 6:00 PM to 11:00 PM
On-Peak	$*0.115592*	for the hours of 2:00 PM to 6:00 PM
Critical Peak Pricing	$*0.950000*	for the hours of 2:00 PM to 6:00 PM during a critical peak event day

Net Metering Program:

The Net Metering Program is available to any eligible customer as described in Rule C11., 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.B, Net Metering Definitions.

A customer who participates in the Net Metering Program is subject to the provisions contained in Rule C11., Net Metering Program.

(Continued on Sheet D-21.00)

GENERAL SERVICE SECONDARY RATE GS

(Continued from Sheet No. D-20.00)

Monthly Rate: (Contd)

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 applicable REP Surcharge and EE Surcharge shown on Sheet D-2.10*, the LIEAF Surcharge on Sheet D-3.00* and the System Access Charge included in the rate, adjusted for any service provision credit. 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 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) self-generation service, (iv) resale for lighting service, or (v) 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.

Capacity Charge:	$10.00	per kW for all kW of Peak Demand during the billing months of June-September
	$8.00	per kW for all kW of Peak Demand during the billing months of October-May
Energy Charge:	$*0.066326*	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: These charges are applicable to Full Service and Retail Open Access (ROA) customers.

System Access Charge:	$30.00	per customer per month
Capacity Charge:	$*1.15*	per kW for all kW of Peak Demand
Distribution Charge:	$*0.030067*	per kWh for all kWh

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-3.10 and the Securitization Charges shown on Sheet Nos. D-5.00 and D-5.10.

(Continued on Sheet No. D-23.00)

M.P.S.C. No. 13 - Electric
Consumers Energy Company **Sheet No. D-24.00**

GENERAL SERVICE SECONDARY DEMAND RATE GSD

(Continued From Sheet No. D-23.00)

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.

Educational Institution Credit: $*(0.000769)* 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 Provision (SG):

Subject to any restrictions, as of June 8, 2012, this provision may be required for any Full Service Customer with a generating installation less than 550 kW operating in parallel with the Company's system, which may employ cogeneration or small power production technology.

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 own, operate and maintain all metering and auxiliary devices (including telecommunication links) at the customer's expense. Meters furnished, installed and maintained by the Company shall meter generation equipment for customers that sell energy to the Company. No refund shall be made for any customer contribution required.

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) Secondary Voltage or Primary Voltage service. The Company will determine the particular nature of the voltage in each case.

Self-generation customers requiring Company delivery service for any portion of the load that has been self-generated will be charged as described in the Delivery Charges section of this Rate Schedule.

There shall be no double billing of demand under the base rate and the Self-Generation Provision.

Sales of Self-Generated Energy to the Company:

A customer who meets the Federal Energy Regulatory Commission's (FERC) criteria for a Qualifying Facility may elect to sell energy to the Company. 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.

Where the customer elects to sell energy to the Company, an Interval Data Meter (IDM)or other applicable meter is required for their generator. 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.

Administrative Cost Charge: *$0.0010 per kWh purchased for generation installations with a capacity of 100 kW or less.*

Energy Purchase:

An energy purchase by the Company shall be bought at the Midwest Independent Transmission System Operator's (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) less $0.005/kWh. The Company may discontinue purchases during system emergencies, maintenance and other operational circumstances.

Dynamic Pricing Pilot:

The Dynamic Pricing Pilot is a voluntary pilot available at the discretion of the Company to Full Service Customers taking service under the Company's GSD tariff and whom have, or are selected to have, the required metering equipment and infrastructure installed. Customer eligibility to participate in this pilot is determined solely by the Company. The Company will furnish, install, maintain and own the required equipment at the customers' premises at the Company's expense for the duration of the pilot. *At the sole discretion of the Company, customers may be allowed to furnish, install and maintain the equipment at the customer's expense.* Equipment *and* installations must conform to the Company's specifications. By enrolling in the pilot, the customer agrees to participate in surveys and understands that the metering data will be used for pilot evaluation purposes. This pilot shall not be taken in conjunction with the GEI Provision or Net Metering.

The Company reserves the right to specify the term of duration of the pilot. The participating customer may elect to terminate service for any reason giving the Company thirty days' notice prior to the customer's next billing cycle. The customer's enrollment shall be terminated if the voluntary pilot ceases or for any reasons as provided for in Rule C1.3, Use of Service.

Deployment of the General Service Dynamic Pricing Pilot is at the sole discretion of the Company and is contingent upon installation of advanced metering infrastructure and supporting critical systems.

Customers that choose to participate in the Dynamic Pricing Pilot will be charged the power supply prices listed below in place of the standard GSD tariff power supply rates for the summer months of June through September. Customers can manage their electric costs by either reducing load during high cost pricing periods or shifting load from high cost pricing periods to lower cost pricing periods. The Company may select a subset of the Dynamic Pricing customers to be provided with additional technology at the Company's expense in order to measure the response difference between customers with and without the additional technology.

(Continued on Sheet No. D-25.00)

GENERAL SERVICE SECONDARY DEMAND RATE GSD

(Continued From Sheet No. D-24.00)

Monthly Rate: (Contd)

Dynamic Pricing Pilot: (Contd)

The Company may call up to eight critical peak events in the summer months of June through September, excluding weekends and holidays, for the on-peak hours of 2:00 PM to 6:00 PM. During a critical peak event, customers will be charged the critical peak price in the place of the on-peak power supply charge. Customers will be notified the day before a critical peak event is expected to occur. Receipt of such notice is the responsibility of the participating customer.

Power Supply Charges: These charges are applicable to Full Service Customers.

Summer Energy Charge

Capacity Charge	$10.00	per kW for all kW of Peak Demand during the billing months of June through September
Off-Peak	$*0.039002*	per kWh for the hours of 12:00 AM to 7:00 AM and 11:00 PM to 12:00 AM
Mid-Peak	$*0.071014*	per kWh for the hours of 7:00 AM to 2:00 PM and 6:00 PM to 11:00 PM
On-Peak	$*0.090565*	per kWh for the hours of 2:00 PM to 6:00 PM
Critical Peak Pricing	$*0.950000*	per kWh for the hours of 2:00 PM to 6:00 PM during a critical peak event day

Net Metering Program:

The Net Metering Program is available to any eligible customer as described in Rule C11., 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.B, Net Metering Definitions.

A customer who participates in the Net Metering Program is subject to the provisions contained in Rule C11., 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.

General Terms:

This rate is subject to all general terms and conditions shown on Sheet No. D-1.00.

Minimum Charge:

The applicable REP Surcharge and EE Surcharge shown on Sheet D-2.10, *the LIEAF Surcharge on Sheet D-3.00* and capacity charges and the System Access Charge included in the rate.

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 .

(Continued on Sheet No. D-26.00)

GENERAL SERVICE SECONDARY DEMAND RATE GSD

(Continued From Sheet No. D-25.00)

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:

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 (CVL 3)

Energy Charge:	$*0.096941*	per kWh for all kWh during the billing months of June-September
	$*0.085418*	per kWh for all kWh during the billing months of October-May

Charges for Customer Voltage Level 2 (CVL 2)

Energy Charge	$*0.091175*	per kWh for all kWh during the billing months of June-September
	$*0.084648*	per kWh for all kWh during the billing months of October-May

Charges for Customer Voltage Level 1 (CVL 1)

Energy Charge	$*0.086179*	per kWh for all kWh during the billing months of June-September
	$*0.079652*	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-4.00.

(Continued on Sheet No. D-27.10)

GENERAL SERVICE PRIMARY RATE GP

(Continued From Sheet No. D-27-00)

Monthly Rate: (Contd)

Delivery Charges: These charges are applicable to Full Service and Retail Open Access (ROA) Customers.

System Access Charge: $50.00 per customer per month

<u>Charges for Customer Voltage Level 3 (CVL 3)</u>

Distribution Charge: $*0.017766* per kWh for all kWh

<u>Charges for Customer Voltage Level 2 (CVL 2)</u>

Distribution Charge: $*0.010974* per kWh for all kWh

<u>Charges for Customer Voltage Level 1 (CVL 1)</u>

Distribution Charge: $*0.008185* per kWh for all kWh

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-3.10 and the Securitization Charges shown on Sheet Nos. D-5.00 and D-5.10.

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, 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.

Substation Ownership Credit: $*(0.000409)* 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 Maximum Demand on each substation 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.

(Continued on Sheet No. D-28.00)

GENERAL SERVICE PRIMARY RATE GP

(Continued From Sheet No. D-27-10)

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.**

Educational Institution Credit: $*(0.000656)* 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 Provision (SG):

As of June 8, 2012, this provision may be required for any Full Service Customer with a generating installation less than 550 kW operating in parallel with the Company’s system, which may employ cogeneration or small power production technology.

All facilities must meet the Parallel Operation Requirements set forth in Rule C1.6 B. The Company shall own, operate and maintain all metering and auxiliary devices (including telecommunication links) at the customer's expense. Meters furnished, installed and maintained by the Company shall meter generation equipment for customers that sell energy to the Company. No refund shall be made for any customer contribution required.

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) Secondary Voltage or Primary Voltage service. The Company will determine the particular nature of the voltage in each case.

Self-generation customers requiring Company delivery service for any portion of the load that has been self-generated will be charged as described in the Delivery Charges section of this Rate Schedule.

Sales of Self-Generated Energy to the Company:

A customer who meets the Federal Energy Regulatory Commission’s (FERC) criteria for a Qualifying Facility may elect to sell energy to the Company. 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.

Where the customer elects to sell energy to the Company, an Interval Data Meter (IDM)or other applicable meter is required for their generator. 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.

Administrative Cost Charge: *$0.0010 per kWh purchased for generation installations with a capacity of 100 kW or less.*

Energy Purchase:

An energy purchase by the Company shall be bought at the Midwest Independent Transmission System Operator's (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) less $0.005/kWh. The Company may discontinue purchases during system emergencies, maintenance and other operational circumstances.

(Continued on Sheet No. D-29. 00)

GENERAL SERVICE PRIMARY RATE GP

(Continued From Sheet No. D-28.00)

Monthly Rate: (Contd)

Dynamic Pricing Pilot

The Dynamic Pricing Pilot is a voluntary pilot available at the discretion of the Company to Full Service Customers taking service under the Company's GP tariff and whom have, or are selected to 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 for the duration of the pilot. *At the sole discretion of the Company, customers may be allowed to furnish, install and maintain the equipment at the customer's expense.* Equipment *and* installations must conform to the Company's specifications. By enrolling in the pilot, the customer agrees to participate in surveys and understands that the metering data will be used for pilot evaluation purposes. This pilot shall not be taken in conjunction with the GEI Provision or Net Metering.

The Company reserves the right to specify the term of duration of the pilot. The participating customer may elect to terminate service for any reason giving the Company thirty days' notice prior to the customer's next billing cycle. The customer's enrollment shall be terminated if the voluntary pilot ceases or for any reasons as provided for in Rule C1.3, Use of Service.

Customers that choose to participate in the Dynamic Pricing Pilot will be charged the power supply prices listed below in place of the standard GP tariff power supply rates for the summer months of June through September. Customers can manage their electric costs by either reducing load during high cost pricing periods or shifting load from high cost pricing periods to lower cost pricing periods. The Company may select a subset of the Dynamic Pricing customers to be provided with additional technology at the Company's expense in order to measure the response difference between customers with and without the additional technology.

Deployment of the General Service Dynamic Pricing Pilot is at the sole discretion of the Company and is contingent upon installation of advanced metering infrastructure and supporting critical systems.

The Company may call up to eight critical peak events in the summer months of June through September, excluding weekends and holidays, for the on-peak hours of 2:00 PM to 6:00 PM. During a critical peak event, customers will be charged the critical peak price in the place of the On-Peak power supply charge. Customers will be notified the day before a critical peak event is expected to occur. Receipt of such notice is the responsibility of the participating customer.

Power Supply Charges: These charges are applicable to Full Service Customers.

Summer Energy Charge for Customer Voltage Level 3 (CVL 3)

	$/kWh	
Off-Peak	$*0.054011*	for the hours of 12:00 AM to 7:00 AM and 11:00 PM to 12:00 AM
Mid-Peak	$*0.090814*	for the hours of 7:00 AM to 2:00 PM and 6:00 PM to 11:00 PM
On-Peak	$*0.119256*	for the hours of 2:00 PM to 6:00 PM
Critical Peak Pricing	$*0.800000*	for the hours of 2:00 PM to 6:00 PM during a critical peak event day

Summer Energy Charge for Customer Voltage Level 2 (CVL 2)

	$/kWh	
Off-Peak	$*0.053241*	for the hours of 12:00 AM to 7:00 AM and 11:00 PM to 12:00 AM
Mid-Peak	$*0.090044*	for the hours of 7:00 AM to 2:00 PM and 6:00 PM to 11:00 PM
On-Peak	$*0.118486*	for the hours of 2:00 PM to 6:00 PM
Critical Peak Pricing	$*0.799230*	for the hours of 2:00 PM to 6:00 PM during a critical peak event day

(Continued on Sheet No. D-29.10)

GENERAL SERVICE PRIMARY RATE GP

(Continued From Sheet No. D-29.00)

Monthly Rate: (Contd)

Dynamic Pricing Pilot (Contd)

Summer Energy Charge for Customer Voltage Level 1 (CVL 1)

	$/kWh	
Off-Peak	$*0.048245*	for the hours of 12:00 AM to 7:00 AM and 11:00 PM to 12:00 AM
Mid-Peak	$*0.085048*	for the hours of 7:00 AM to 2:00 PM and 6:00 PM to 11:00 PM
On-Peak	$*0.113490*	for the hours of 2:00 PM to 6:00 PM
Critical Peak Pricing	$*0.796441*	for the hours of 2:00 PM to 6:00 PM during a critical peak event day

Net Metering Program:

The Net Metering Program is available to any eligible customer as described in Rule C11., 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.B, Net Metering Definitions.

A customer who participates in the Net Metering Program is subject to the provisions contained in Rule C11., 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.

General Terms:

This rate is subject to all general terms and conditions shown on Sheet No. D-1.00.

Minimum Charge:

The applicable REP Surcharge and EE Surcharge shown on Sheet D-2.10*, the LIEAF Surcharge on Sheet D-3.00* and capacity charges and the System Access Charge included in the rate.

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.

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 self-generation 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 (CVL 3)

Capacity Charge:	$*21.05*	per kW of On-Peak Billing Demand during the billing months of June-September
	$*18.05*	per kW of On-Peak Billing Demand during the billing months of October-May
Energy Charge:	$*0.054129*	per kWh for all On-Peak kWh during the billing months of June-September
	$*0.037294*	per kWh for all Off-Peak kWh during the billing months of June-September
	$*0.046202*	per kWh for all On-Peak kWh during the billing months of October-May
	$*0.040430*	per kWh for all Off-Peak kWh during the billing months of October-May

Charges for Customer Voltage Level 2 (CVL 2)

Capacity Charge:	$*20.05*	per kW of On-Peak Billing Demand during the billing months of June-September
	$*17.05*	per kW of On-Peak Billing Demand during the billing months of October-May
Energy Charge:	$*0.053359*	per kWh for all On-Peak kWh during the billing months of June-September
	$*0.036524*	per kWh for all Off-Peak kWh during the billing months of June-September
	$*0.045432*	per kWh for all On-Peak kWh during the billing months of October-May
	$*0.039660*	per kWh for all Off-Peak kWh during the billing months of October-May

(Continued on Sheet No. D-31.10)

M.P.S.C. No. 13 - Electric
Consumers Energy Company **Sheet No. D-31.10**

GENERAL SERVICE PRIMARY DEMAND RATE GPD

(Continued From Sheet No. D-31.00)

Monthly Rate: (Contd)

Power Supply Charges: These charges are applicable to Full Service Customers. (Contd)

Charges for Customer Voltage Level 1 (CVL 1)

Capacity Charge:	$*19.05*	per kW of On-Peak Billing Demand during the billing months of June-September
	$*16.05*	per kW of On-Peak Billing Demand during the billing months of October-May
Energy Charge:	$*0.048363*	per kWh for all On-Peak kWh during the billing months of June-September
	$*0.031528*	per kWh for all Off-Peak kWh during the billing months of June-September
	$*0.040436*	per kWh for all On-Peak kWh during the billing months of October-May
	$*0.034664*	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-4.00.

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 (CVL 3)

Capacity Charge: $*4.10* per kW of Maximum Demand

Charges for Customer Voltage Level 2 (CVL 2)

Capacity Charge: $*2.28* per kW of Maximum Demand

Charges for Customer Voltage Level 1 (CVL 1)

Capacity Charge: $*0.67* per kW of Maximum Demand

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-3.10 and the Securitization Charges shown on Sheet Nos. D-5.00 and D-5.10.

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 *0.850 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.

(Continued on Sheet No. D-32.00)

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 billing month, but never 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.

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.**

Substation Ownership Credit: $(0.30) 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 Maximum Demand on each substation 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.

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.

(Continued on Sheet No. D-32.00)

GENERAL SERVICE PRIMARY DEMAND RATE GPD

(Continued From Sheet No. D-33.00)

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.**

Educational Institution Credit:

$*(0.000336)* 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-34.10)

GENERAL SERVICE PRIMARY DEMAND RATE GPD

(Continued From Sheet No. D-34.00)

Monthly Rate: (Contd)

Self-Generation Provision (SG):

Subject to any restrictions, as of June 8, 2012, this provision may be required for any Full Service Customer with a generating installation less than 550 kW operating in parallel with the Company's system, which may employ cogeneration or small power production technology.

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 own, operate and maintain all metering and auxiliary devices (including telecommunication links) at the customer's expense. Meters furnished, installed and maintained by the Company shall meter generation equipment for customers that sell energy to the Company. No refund shall be made for any customer contribution required.

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) Secondary Voltage or Primary Voltage service. The Company will determine the particular nature of the voltage in each case.

Self-generation customers requiring Company delivery service for any portion of the load that has been self-generated will be charged as described in the Delivery Charges section of this Rate Schedule.

There shall be no double billing of demand under the base rate and the Self-Generation Provision.

Sales of Self-Generated Energy to the Company:

A customer who meets the Federal Energy Regulatory Commission's (FERC) criteria for a Qualifying Facility may elect to sell energy to the Company. 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.

Where the customer elects to sell energy to the Company, an Interval Data Meter (IDM) or other applicable meter is required for their generator. 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.

Administrative Cost Charge: *$0.0010 per kWh purchased for generation installations with a capacity of 100 kW or less.*

Energy Purchase:

An energy purchase by the Company shall be bought at the Midwest Independent Transmission System Operator's (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) less $0.005/kWh. The Company may discontinue purchases during system emergencies, maintenance and other operational circumstances.

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 50,000 kW. The aggregate amount of monthly On-Peak Billing Demand subscribed under this provision shall be limited to 250,000 kW.

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.

(Continued on Sheet No. D-35.00)

GENERAL SERVICE PRIMARY DEMAND RATE GPD

(Continued From Sheet No. D-34.10)

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. Within 10 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.

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 Midwest Independent Transmission System Operator (MISO) requirements as determined by the Company and 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.

<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 endeavor to provide notice in advance of probable interruption, and if possible, a second notice of positive interruption. However, this service shall be interrupted immediately upon notice should the Company deem such action necessary. 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 $50.00 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
	$(4.00)	per kW of On-Peak Billing Demand during the billing months of October-May

(Continued of Sheet No. D-36.00)

GENERAL SERVICE PRIMARY DEMAND RATE GPD

(Continued From Sheet No. D-35.00)

Monthly Rate: (Contd)

Net Metering Program:

The Net Metering Program is available to any eligible customer as described in Rule C11., 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.B, Net Metering Definitions.

A customer who participates in the Net Metering Program is subject to the provisions contained in Rule C11., 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.

General Terms:

This rate is subject to all general terms and conditions shown on Sheet No. D-1.00.

Minimum Charge:

The applicable REP Surcharge and EE Surcharge shown on Sheet D-2.10*, the LIEAF Surcharge on Sheet D-3.00* and capacity charges and the System Access Charge included in the rate.

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 Resale Service Provision, (ii) service under the Green Generation Program, (iii) service under the Educational Institution Service Provision, (iv) service under the Aggregate Peak Demand Service Provision, (v) service under the Interruptible 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.

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.

GENERAL SERVICE PRIMARY TIME-OF-USE PILOT RATE GPTU

Availability:

Subject to any restrictions, this experimental General Service Primary Time-Of-Use (GPTU) Pilot Rate is available to any Full Service Customer with a Maximum Demand of 5 MW or less taking service at the Company's Primary Voltage level. This rate is limited to *100 MW* of Maximum Demand capacity.

If the capacity of all customers requesting service in writing under this rate exceeds *100 MW* of Maximum Demand capacity to be served on Pilot rate GPTU will be awarded based on a *first-come, first-served basis after receipt of the MPSC Order approving the 100 MW limit*.
This pilot rate is effective for bills rendered during the billing month which begins a minimum of thirty days after issuance of the final Order in Case No. U-17087 and remains in effect for five years.

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 D-36.20)

M.P.S.C. No. 13 - Electric
Consumers Energy Company **Sheet No. D-36.20**

GENERAL SERVICE PRIMARY TIME-OF-USE PILOT RATE GPTU

(Continued from Sheet No. D-36.10)

Monthly Rate:

Power Supply Charges:

Charges for Customer Voltage Level 3 (CVL 3)

Energy Charge:

Off-Peak - Summer	$*0.055964*	per kWh during the calendar months of June - September
Low-Peak - Summer	$*0.072945*	per kWh during the calendar months of June - September
Mid-Peak - Summer	$*0.099187*	per kWh during the calendar months of June - September
High-Peak - Summer	$*0.122218*	per kWh during the calendar months of June - September
Off-Peak - Winter	$*0.071982*	per kWh during the calendar months of October - May
Mid-Peak - Winter	$*0.086656*	per kWh during the calendar months of October - May
High-Peak - Winter	$*0.091407*	per kWh during the calendar months of October - May

Charges for Customer Voltage Level 2 (CVL 2)

Energy Charge:

Off-Peak - Summer	$*0.055194*	per kWh during the calendar months of June - September
Low-Peak - Summer	$*0.072175*	per kWh during the calendar months of June - September
Mid-Peak - Summer	$*0.098417*	per kWh during the calendar months of June - September
High-Peak - Summer	$*0.121448*	per kWh during the calendar months of June - September
Off-Peak - Winter	$*0.071212*	per kWh during the calendar months of October - May
Mid-Peak - Winter	$*0.085886*	per kWh during the calendar months of October - May
High-Peak - Winter	$*0.090637*	per kWh during the calendar months of October - May

Charges for Customer Voltage Level 1 (CVL 1)

Energy Charge:

Off-Peak - Summer	$*0.050198*	per kWh during the calendar months of June - September
Low-Peak - Summer	$*0.067179*	per kWh during the calendar months of June - September
Mid-Peak - Summer	$*0.093421*	per kWh during the calendar months of June - September
High-Peak - Summer	$*0.116452*	per kWh during the calendar months of June - September
Off-Peak - Winter	$*0.066216*	per kWh during the calendar months of October - May
Mid-Peak - Winter	$*0.080890*	per kWh during the calendar months of October - May
High-Peak - Winter	$*0.085641*	per kWh during the calendar months of October - May

Delivery Charges:

System Access Charge: $100.00 per customer 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: $*2.28* per kW of Maximum Demand

Charges for Customer Voltage Level 1 (CVL 1)

Capacity Charge: $*0.67* per kW of Maximum Demand

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-3.10 and the Securitization Charges shown on Sheet Nos. D-5.00 and D-5.10.

(Continue on Sheet No. D-36.30)

GENERAL SERVICE PRIMARY TIME-OF-USE PILOT RATE GPTU

(Continued from Sheet No. D-36.20)

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 *0.850 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 Customers.

Substation Ownership Credit: $(0.30) 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 Maximum Demand on each substation 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 Provision (SG):

Subject to any restrictions, as of June 8, 2012, this provision may be required for any Full Service Customer with a generating installation less than 550 kW operating in parallel with the Company's system, which may employ cogeneration or small power production technology.

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 own, operate and maintain all metering and auxiliary devices (including telecommunication links) at the customer's expense. Meters furnished, installed and maintained by the Company shall meter generation equipment for customers that sell energy to the Company. No refund shall be made for any customer contribution required.

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) Secondary Voltage or Primary Voltage service. The Company will determine the particular nature of the voltage in each case.

Self-generation customers requiring Company delivery service for any portion of the load that has been self-generated will be charged as described in the Delivery Charges section of this Rate Schedule.

There shall be no double billing of demand under the base rate and the Self-Generation Provision.

Sales of Self-Generated Energy to the Company:

A customer who meets the Federal Energy Regulatory Commission's (FERC) criteria for a Qualifying Facility may elect to sell energy to the Company. 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.

Where the customer elects to sell energy to the Company, an Interval Data Meter (IDM)or other applicable meter is required for their generator. 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.

Administrative Cost Charge:

$0.0010 per kWh purchased for generation installations with a capacity of 100 kW or less.

Energy Purchase:

An energy purchase by the Company shall be bought at the Midwest Independent Transmission System Operator's (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) less $0.005/kWh. The Company may discontinue purchases during system emergencies, maintenance and other operational circumstances.

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 applicable REP Surcharge and EE Surcharge shown on Sheet D-2.10, *the LIEAF Surcharge on Sheet D-3.00* and capacity charges and the System Access Charge included in the rate.

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.

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*. This rate is limited to existing metal melting customers taking service under the Company's Furnace/Metal Melting Service Provision (GFM), on June 7, 2012, the date of the final order in Case No. U-16794. 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 and have an annual load factor that exceeds 70%.* New electric metal melting *or energy intensive* 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 (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-37.10)

ENERGY INTENSIVE PRIMARY RATE *EIP*

(Continued from Sheet No. D-37.00)

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:	3:00 PM to 5:00 PM 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:	5:00 PM to 7:00 PM 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:

<u>Charges for Customer Voltage Level 3 (CVL 3)</u>

Energy Charge:

Off-Peak – Summer	$*0.041226*	per kWh during the calendar months of June - September
Low-Peak - Summer	$*0.066725*	per kWh during the calendar months of June - September
Mid-Peak - Summer	$*0.081086*	per kWh during the calendar months of June - September
High-Peak - Summer	$*0.093222*	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	$*0.062473*	per kWh during the calendar months of October - May
Mid-Peak - Winter	$*0.070493*	per kWh during the calendar months of October - May
High-Peak- Winter	$*0.071782*	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-37.20)

ENERGY INTENSIVE PRIMARY RATE *EIP*

(Continued from Sheet No. D-37.10)

Power Supply Charges: (Contd)

Charges for Customer Voltage Level 2 (CVL 2)

Energy Charge:

Off-Peak - Summer	$*0.040456*	per kWh during the calendar months of June - September
Low-Peak - Summer	$*0.065955*	per kWh during the calendar months of June - September
Mid-Peak - Summer	$*0.080316*	per kWh during the calendar months of June - September
High-Peak - Summer	$*0.092452*	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	$*0.061703*	per kWh during the calendar months of October - May
Mid-Peak - Winter	$*0.069723*	per kWh during the calendar months of October - May
High-Peak- Winter	$*0.071012*	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 (CVL 1)

Energy Charge:

Off-Peak - Summer	$*0.035460*	per kWh during the calendar months of June - September
Low-Peak - Summer	$*0.060959*	per kWh during the calendar months of June - September
Mid-Peak - Summer	$*0.075320*	per kWh during the calendar months of June - September
High-Peak - Summer	$*0.087456*	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	$*0.056707*	per kWh during the calendar months of October - May
Mid-Peak - Winter	$*0.064727*	per kWh during the calendar months of October - May
High-Peak- Winter	$*0.066016*	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

Delivery Charges:

System Access Charge: $100.00 per customer per month

Charges for Customer Voltage Level 3 (CVL 3):

Capacity Charge:	$1.00	per kW of Maximum Demand
Distribution Charge:	$*0.011579*	per kWh for all kWh for a Full Service Customer

Charges for Customer Voltage Level 2 (CVL 2):

Capacity Charge:	$0.50	per kW of Maximum Demand
Distribution Charge:	$*0.004787*	per kWh for all kWh for a Full Service Customer

Charges for Customer Voltage Level 1 (CVL 1):

Capacity Charge:	$0.30	per kW of Maximum Demand
Distribution Charge:	$*0.001998*	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-3.10 and the Securitization Charges shown on Sheet Nos. D-5.00 and D-5.10.

(Continued on Sheet No. D-37.30)

ENERGY INTENSIVE PRIMARY RATE *EIP*

(Continued from Sheet No. D-37.20)

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 *0.850, 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 Customers.

Substation Ownership Credit: $(0.30) 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 Maximum Demand on each substation 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 Provision (SG):

Subject to any restrictions, as of June 8, 2012, this provision may berequired for any Full Service Customer with a generating installation less than 550 kW operating in parallel with the Company's system, which may employ cogeneration or small power production technology.

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 own, operate and maintain all metering and auxiliary devices (including *telecommunication links) at the customer's expense. Meters furnished, installed and maintained by the Company shall meter generation equipment for customers that sell energy to the Company. No refund shall be made for any customer contribution required.*

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) Secondary Voltage or Primary Voltage service. The Company will determine the particular nature of the voltage in each case.

Self-generation customers requiring Company delivery service for any portion of the load that has been self-generated will be charged as described in the Delivery Charges section of this Rate Schedule.

There shall be no double billing of demand under the base rate and the Self-Generation Provision.

Sales of Self-Generated Energy to the Company:

A customer who meets the Federal Energy Regulatory Commission's (FERC) criteria for a Qualifying Facility may elect to sell energy to the Company. 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.

Where the customer elects to sell energy to the Company, an Interval Data Meter (IDM)or other applicable meter is required for their generator. 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.

Administrative Cost Charge:

$0.0010 per kWh purchased for generation installations with a capacity of 100 kW or less.

Energy Purchase:

An energy purchase by the Company shall be bought at the Midwest Independent Transmission System Operator's (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) less $0.005/kWh. The Company may discontinue purchases during system emergencies, maintenance and other operational circumstances.

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 applicable REP Surcharge and EE Surcharge shown on sheet D-2.10, *the LIEAF Surcharge on Sheet D-3.00* and capacity charges and the System Access Charge included in the rate.

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.

GENERAL SERVICE SELF GENERATION RATE GSG-2

(Continued From Sheet No. D-42.00)

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 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.

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.

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 Standby Demand

Charges for Customer Voltage Level 2 (CVL 2)

Capacity Charge:	$*2.28*	per kW of Standby Demand

Charges for Customer Voltage Level 1 (CVL 1)

Capacity Charge:	$*0.67*	per kW of Standby Demand

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-3.10 and the Securitization Charges shown on Sheet Nos. D-5.00 and D-5.10.

(Continued on Sheet No. D-44.00)

GENERAL SERVICE SELF GENERATION RATE GSG-2

(Continued From Sheet No. D-43.00)

Monthly Rate: (Contd)

Standby Charges: (Contd)

Adjustment for Power Factor:

For all energy supplied by the Company, the adjustment for the Power Factor shall be as provided for under the customer's otherwise applicable Company Full Service firm Rate Schedule.

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:

Substation Ownership Credit: $(0.30) per kW of Standby 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 Maximum Demand on each substation 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.

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: $ (0.67) per kW of Standby 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 Midwest Independent Transmission System Operator's (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) less $0.005/kWh.

General Terms:

This rate is subject to all general terms and conditions shown on Sheet No. D-1.00.

(Continued on Sheet No D-45.00)

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: $*0.053960* per kWh for all kWh

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-4.00.

(Continued on Sheet No. D-47.00)

GENERAL SERVICE METERED LIGHTING RATE GML
(Continued from Sheet No. D-46.00)

Monthly Rate: (Contd)

Secondary Delivery Charge:

System Access Charge:	$10.00	per customer per month
Distribution Charge:	$*0.054791*	per kWh for all kWh

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-3.10 and the Securitization Charges shown on Sheet Nos. D-5.00 and D-5.10.

Primary Power Supply Charge:

Energy Charge:	$*0.026481*	per kWh for all kWh

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-4.00.

Primary Delivery Charge:

System Access Charge:	$20.00	per customer per month
Distribution Charge:	$*0.041004*	per kWh for all kWh

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-3.10 and the Securitization Charges shown on Sheet Nos. D-5.00 and D-5.10.

Net Metering Program:

The Net Metering Program is available to any eligible customer as described in Rule C11., 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.B, Net Metering Program.

A customer who participates in the Net Metering Program is subject to the provisions contained in Rule C11., 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-48.00)

GENERAL SERVICE METERED LIGHTING RATE GML
(Continued from Sheet No. D-47.00)

Monthly Rate: (Contd)

General Terms:

This rate is subject to all general terms and conditions shown on Sheet No . D-1.00.

Minimum Charge:

The applicable REP Surcharge and EE Surcharge shown on sheet D-2.10*, the LIEAF Surcharge on Sheet D-3.00* and the System Access Charge included in the rate.

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.

Special Terms and Conditions:

The Company reserves the right to make special contractual arrangements as to term or duration of contract, termination charges, contribution in aid of construction, annual charges or other special considerations when the customer requests service, equipment or facilities not normally provided under this rate.

Hours of Lighting:

Metered Lights shall be controlled to burn only when the natural general level of illumination is lower than about 3/4 footcandle. Under normal conditions this is approximately one-half hour after sunset until approximately one-half hour before sunrise. For dusk to midnight service, luminaires shall be controlled to turn off anytime between 11:00 PM, Eastern standard time, and dawn. The turnoff time within a given municipality shall be the same at all locations.

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 LIGHTING RATE GUL

(Continued From Sheet No. D-50.10)

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)	**Fixture Charge per Luminaire** (4)
Mercury Vapor (3)	100	128	3,500	$*5.44*	$6.00
Mercury Vapor (3)	175	209	7,500	*8.88*	6.00
Mercury Vapor (3)	250	281	10,000	*11.94*	6.00
Mercury Vapor (3)	400	458	20,000	*19.46*	6.00
Mercury Vapor (3)	700	770	35,000	*32.72*	6.00
Mercury Vapor (3)	1,000	1,080	50,000	*45.89*	6.00
High-Pressure Sodium (3)	70	83	5,000	*3.53*	6.00
High-Pressure Sodium	100	117	8,500	*4.97*	6.00
High-Pressure Sodium	150	171	14,000	*7.27*	6.00
High-Pressure Sodium (3)	200	247	20,000	*10.49*	6.00
High-Pressure Sodium	250	318	24,000	*13.51*	6.00
High-Pressure Sodium	400	480	45,000	*20.39*	6.00
Fluorescent (3)	380	470	20,000	*19.97*	6.00
Incandescent (3)	202	202	2,500	*8.58*	6.00
Incandescent (3)	305	305	4,000	*12.96*	6.00
Incandescent (3)	405	405	6,000	*17.21*	6.00
Incandescent (3)	690	690	10,000	*29.32*	6.00
Metal Halide	150	170	9,750	*7.22*	6.00
Metal Halide (3)	175	210	10,500	*8.92*	6.00
Metal Halide	250	290	15,500	*12.32*	6.00
Metal Halide	400	460	24,000	*19.54*	6.00

(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, Securitization and Securitization Tax Charges, Power Plant Securitization Charges and surcharges.

(3) Rates apply to existing luminaires only and are not open to new business.

(4) For customers who own their lighting fixtures and are assessed a Service Charge (but not a Fixture Charge), the charge per luminaire represents a *43*% Power Supply Charge and a *57*% Distribution Charge. For customers who do not own their lighting fixtures and are assessed both a Service Charge and a Fixture Charge, the charge per luminaire represents a *24.2*% Power Supply Charge and a *75.8*% 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-52.00)

GENERAL SERVICE UNMETERED LIGHTING RATE GUL

(Continued From Sheet No. D-53.00)

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 capacity requirements in watts of the lamp (s) including ballast(s) times the monthly Burning Hours as defined below divided by 1,000.

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 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. For 24-hour service, unmetered lighting shall be burning 24 hours per day.

The Company shall replace or repair, at its own cost, unmetered 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.

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.

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 UNMETERED EXPERIMENTAL LIGHTING RATE GU-XL

(Continued From Sheet No. D-54.01)

Facilities Policy (contd):

Company-Owned Option (contd)

D. The Company will determine the type and size of all experimental 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 experimental lighting available under this rate.

E. The Company shall determine all associated equipment necessary to provide service under the Company-Owned Unmetered Experimental Lighting option.

F. Any charges, deposits or contributions may be required in advance of commencement of construction.

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:

Power Supply Charges:

Energy Charge:	$*0.052012*	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:	$*0.054258*	per kWh for all kWh

Delivery Charges Company-Owned Option:

Distribution Charge:	$*0.055508*	per kWh for all kWh
Fixture Charge per Luminaire:	$6.00	per month

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-3.10 and the Securitization Charges shown on Sheet Nos. D-5.00 and D-5.10.

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 Experimental 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.

(Continued on Sheet No. D-54.03)

GENERAL UNMETERED EXPERIMENTAL LIGHTING RATE GU-XL

(Continued From Sheet No. D-54.02)

Maintenance of Lighting:

The Company shall replace or repair, at its own cost, Company-Owned Unmetered Experimental 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.

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.

Term and Form of Contract:

All service under this rate shall require a written contract with an initial term of two 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:	$*0.071963*	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:

System Access Charge:	$2.00	per customer per month
Distribution Charge:	$*0.014438*	per kWh for all kWh

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-3.10 and the Securitization Charges shown on Sheet Nos. D-5.00 and D-5.10.

(Continued on Sheet No. D-55.00)

GENERAL SERVICE UNMETERED RATE GU
(Continued from Sheet No. D-55.00)

Monthly Rate: (Contd)

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 applicable REP Surcharge and EE Surcharge shown on sheet D-2.10, *the LIEAF Surcharge on Sheet D-3.00* and the System Access Charge included in the rate.

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.

Special Terms and Conditions:

The Company reserves the right to make special contractual arrangements as to term or duration of contract, termination charges, contribution in aid of construction, monthly charges or other special considerations when the customer requests service, equipment or facilities not normally provided under this rate.

Term and Form of Contract:

Traffic Lighting, Wireless Access and Security Camera service under this rate may require a written contract for a term of reasonable duration.

All service under this rate to Community Antenna Television Service Companies shall require a written contract with a minimum term of one year.

(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, 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 load-profiled customer with maximum demand of 20 kW or less may receive meter reads by conventional means. If the load-profiled account exceeds a maximum demand of 20 kW, 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 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 that 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. 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 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.

RETAIL OPEN ACCESS PRIMARY RATE ROA-R

(Continued From Sheet No. E-22.00)

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 *7.239%* 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-3.10 and the Securitization Charges shown on Sheet Nos. D-5.00 and D-5.10. 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.

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 PRIMARY RATE ROA-S

(Continued From Sheet No. E-24.00)

Metering Requirements:

The ROA Customer with a Maximum Demand of less than 20 kW shall be separately metered by 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 AccessCharge, 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 an Interval Data Meterof 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 AccessCharge, 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 Metershall 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 *7.239%* 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-26.00)

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 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 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%	*0.784%*
Customer Voltage Level 2	*1.340%*	*2.434%*
Customer Voltage Level 3	*3.339%*	*7.239%*

(Continued on Sheet No. E-28.00)

P R O O F O F S E R V I C E

STATE OF MICHIGAN)

Case No. U-17735

County of Ingham)

Joanna Klein being duly sworn, deposes and says that on November 19, 2015 A.D. she served a copy of the attached Commission order by first class mail, postage prepaid, or by inter-departmental mail, to the persons as shown on the attached service list.

Joanna Klein

Joanna Klein

Subscribed and sworn to before me
This 19th day of November 2015

Lisa Felice

Lisa Felice
Notary Public, Eaton County, Michigan
My commission expires on April 15, 2020

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