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November 6, 2025

Ms. Lisa Felice
Executive Secretary
Michigan Public Service Commission
7109 W. Saginaw Highway
Lansing, MI 48909

Re: MPSC Case No. U-21870

Dear Ms. Felice:

Enclosed herewith for filing in the above-referenced matter, please find the Official Exhibits of Solar Technology, LLC, and Proof of Service regarding same.

Very truly yours,

Jennifer Utter Heston

Jennifer U. Heston
Digitally signed by Jennifer U. Heston
Date: 2025.11.06 13:02:29 -05'00'

Enclosures
Cc: All Parties of Record

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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

EXHIBIT LIST
OF SOLAR TECHNOLOGY LLC

Exhibit Number:	**Witness:**	**Description:**
SLT-1 (MPG-1)	Michael P. Gorman	Direct Testimony of Laura M. Connolly, U-21585
SLT-2 (MPG-2)	Michael P. Gorman	Consumers' Power Factor Report, U-21224
SLT-3 (MPG-3)	Michael P. Gorman	Discovery Response U21870-SLT-CE-0241

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the generation and distribution of electricity and for other relief.	))))))	Case No. U-21585

DIRECT TESTIMONY

OF

LAURA M. CONNOLLY

ON BEHALF OF

CONSUMERS ENERGY COMPANY

May 2024

LAURA M. CONNOLLY
U-21585 DIRECT TESTIMONY

Q. Please state your name and business address.

A. My name is Laura M. Connolly, and my business address is One Energy Plaza, Jackson, Michigan 49201.

Q. By whom are you employed and in what capacity?

A. I am employed by Consumers Energy Company ("Consumers Energy" or the "Company") as Director of Regulated Pricing in the Rates and Regulation Department.

Q. Please describe your educational background and business experience.

A. I received a Bachelor of Business Administration degree in Finance in December 2000 from the University of Michigan – Flint. In January 2001, I joined Consumers Energy as a Rate Analyst in the Revenue Requirements section of the Rates Department, where I held positions of increasing responsibility. I joined the Cost Analysis, Pricing and Tariff section of the Rates Department in 2012 and was promoted to Director of Regulated Pricing in July 2021.

Q. What are your responsibilities as Director of Regulated Pricing for Consumers Energy?

A. In my current role I oversee the development of the Company's cost-of-service study ("COSS"), load research, rate design, and other rate-related analyses.

Q. Have you previously filed testimony with the Michigan Public Service Commission ("MPSC" or the "Commission")?

A. Yes. I have filed testimony in the following cases:

Case No. U-12575-R	Gas Cost Recovery Reconciliation;
Case No. U-13220	Gas Cost Recovery Plan;
Case No. U-13570	Gas Cost Recovery Plan;
Case No. U-13570-R	Gas Cost Recovery Reconciliation;

LAURA M. CONNOLLY
U-21585 DIRECT TESTIMONY

Case No. U-13730	Gas General Rate Case;
Case No. U-13916	Gas Cost Recovery Plan;
Case No. U-13917-R	Power Supply Cost Recovery ("PSCR") Reconciliation;
Case No. U-14274-R	PSCR Reconciliation;
Case No. U-14347	Electric General Rate Case;
Case No. U-14403	Gas Cost Recovery Plan;
Case No. U-14403-R	Gas Cost Recovery Reconciliation;
Case No. U-14701-R	PSCR Reconciliation;
Case No. U-14716	Gas Cost Recovery Plan;
Case No. U-14716-R	Gas Cost Recovery Reconciliation;
Case No. U-15001-R	PSCR Reconciliation;
Case No. U-15415-R	PSCR Reconciliation;
Case No. U-15454	Gas Cost Recovery Plan;
Case No. U-15675-R	PSCR Reconciliation;
Case No. U-16045	PSCR Plan;
Case No. U-16045-R	PSCR Reconciliation;
Case No. U-16736	Energy Optimization Reconciliation;
Case No. U-16432	PSCR Plan;
Case No. U-16432-R	PSCR Reconciliation;
Case No. U-16890	PSCR Plan;
Case No. U-17197	Gas General Rate Case;
Case No. U-17281	Energy Optimization Reconciliation;
Case No. U-17601	Energy Optimization Reconciliation;
Case No. U-17688	Public Act 169 of 2014;
Case No. U-17735	Electric General Rate Case;

Case No. U-17990	Electric General Rate Case;	
Case No. U-18322	Electric General Rate Case;	
Case No. U-20134	Electric General Rate Case;	
Case No. U-20102	Electric Tax Credit A;	
Case No. U-20286	Electric Tax Credit B;	
Case No. U-20563	Demand Response Reconciliation;	
Case No. U-20889	Securitization of Karn Units 1 and 2;	
Case No. U-20803	PSCR Reconciliation;	
Case No. U-21308	Gas General Rate Case;	
Case No. U-21049	PSCR Reconciliation;	
Case No U-21321	Energy Waste Reduction Plan; and	
Case No U-21258	PSCR Reconciliation.	

Q. What is the purpose of your direct testimony?

A. The purpose of my direct testimony is to present the Company's electric COSS for the forecasted 12-month period ending February 28, 2026 ("test year") and sponsor related proposals. In addition, I will sponsor the Company's proposed rate design that will result in electric revenues sufficient to collect the total revenue requirement proposed by the Company in this case.

Q. Are you sponsoring any exhibits?

A. Yes. I am sponsoring the following exhibits:

Exhibit A-16 (LMC-1) Schedule F-1		Electric Cost-of-Service Study – Projected 12-Month Period Ending Feb 28, 2026, Version 1;
Exhibit A-59 (LMC-2)		Capacity Related Cost and Charge Calculation (SRM);
Exhibit A-60 (LMC-3)		Substation Ownership Credit;

Exhibit A-61 (LMC-4)		Allocation of Surcharges;
Exhibit A-16 (LMC-5)	Schedule F-2.0	Summary of Present and Proposed Revenues by Rate Schedule;
Exhibit A-16 (LMC-6)	Schedule F-2.1	Calculation of Rate Design Targets;
Exhibit A-16 (LMC-7)	Schedule F-3.0	Present and Proposed Revenue Detail;
Exhibit A-16 (LMC-8)	Schedule F-4.0	Comparison of Present and Proposed Monthly Bills;
Exhibit A-62 (LMC-9)		Demand Response Surcharge (DR);
Exhibit A-63 (LMC-10)		Electric Rate Case (ERC) Deferral Surcharge;
Exhibit A-64 (LMC-11)		Investment Recovery Mechanism (IRM) Surcharge;
Confidential Exhibit A-65 (LMC-12)		Long-Term Industrial Load Retention Rate (LTILRRR) Revenues;
Confidential Exhibit A-66 (LMC-13)		Large Economic Development Rate (LEDR) Revenues; and
Exhibit A-67 (LMC-14)		Power Factor Calculation.

Q. Were these exhibits prepared by you or under your supervision?

A. Yes.

Q. How is your direct testimony organized?

A. My direct testimony is organized as follows:

I. COST OF SERVICE OVERVIEW

II. TEST YEAR ELECTRIC COSS

III. TEST YEAR ELECTRIC COSS- VERSION 1

IV. SRM CAPACITY CHARGE CALCULATION

V. SUBSTATION OWNERSHIP CREDIT CALCULATION

VI. ALLOCATION OF SURCHARGES

VII. RATE DESIGN OVERVIEW

VIII. RATE DESIGN PROPOSALS

IX. SURCHARGES

I. COST OF SERVICE OVERVIEW

Q. What is a COSS?

A. A COSS is a three-part analysis that quantifies the utility's cost to serve each rate class. The COSS filed in this case serves two primary purposes. First, it identifies and assigns the utility's electric production and distribution costs to the jurisdictional electric rate classes. Second, the COSS is used to determine the contribution of each jurisdictional electric rate class to jurisdictional earnings. Ultimately the information provided by the COSS is used to guide rate design among other things. The fundamental guiding principle used to assign costs in the COSS is cost causation. In other words, the costs assigned to a class or group of customers should reflect how those customers drive or influence the utility's costs.

Q. What are the three parts or steps involved in performing a COSS?

A. The first step is functionalization, followed by classification, and finally allocation. Cost functionalization involves the identification and separation of plant and expenses into specific categories based on the activity or "function" that each cost is incurred to provide/support. Consumers Energy's electric functional cost categories are production and distribution. Cost classification, the second step, involves the categorization of functionalized costs into demand, customer, and energy components according to the primary cost drivers. The final step is cost allocation. Allocation assigns costs to each customer class using a variety of factors that correlate to the identified cost drivers. Common allocation factors include energy use, demand, and number of customers among others. When possible, individual costs that can be traced to a class of customers are

"specifically assigned" to that particular class. This process is relatively standard across the utility industry and is supported by the National Association of Regulatory Utility Commissioners ("NARUC") Electric Rate Design Manual.

Q. How does the Company present the results of its COSS?

A. The Company presents the results of its COSS in compliance with the Commission's Standard Filing Requirements that were approved in Case No. U-18238.

Q. Are retail open access (electric choice) customers included in the Company's COSS?

A. Yes. Retail open access ("ROA") customers are included in the full-service class that they would be assigned to if they were on full-service tariffs since distribution costs are the same for both ROA and full-service customers.

II. TEST YEAR ELECTRIC COSS

Q. How were the test year input allocation schedules developed?

A. There are 18 distinct allocation input schedules in the electric COSS. Each schedule was developed to allocate to each customer class its utilization of a particular part of the electrical system. Nine schedules are based on energy at generation, three schedules are based on the demand that a class places on the various portions of the electrical system, and the remaining schedules are based on revenues, sales, or customer levels. The schedule numbers are shown on Exhibit A-16 (LMC-1), Schedule F-1, pages 10 through 12. The energy schedules (100-108) are based on customer energy use measured at different times, seasons, and in total. The demand schedules are based on various measures of Coincident Peak ("CP") demand (schedules 120 and 121) and Class Peak demand (schedule 127). Total revenue, billed sales, number of customers, and customers weighted on average meter expense were the basis for schedules 141 through 143, 150, 160, and 170, respectively.

The allocation schedules were developed using test year revenue, sales and customer data, Company records, load research samples, and quantitative methods to determine the extent that each customer class uses the various portions of the electrical system (expressed as a percentage). The percentages determined in the allocation schedules were used to calculate class cost responsibility in the COSS. Because all customer classes do not utilize the full distribution system to take delivery of electrical service, the allocation schedules were developed to assign only the portions of the system used by each customer class.

Q. How were the demand and energy input allocation schedules developed?

A. A three-year average of historic energy use profiles (2020, 2021, and 2022) was used to develop an average test year profile for each customer class. Then, the loss factors sponsored by Company witness Michael P. Kelly were applied to the average test year profile to arrive at generation and voltage level usage. This information was then used to develop the demand and energy allocation schedules.

Q. How were the historic load profiles developed?

A. The Company utilizes an external consultant to develop an average load profile. The consultant uses load research software to extrapolate a total class profile based on the Company's meter data from each customer class. Load profiles for street lighting were assumed to follow daylight hours, and the profiles for unmetered usage were assumed to be a flat average use per hour.

Q. Were load profiles based on sample data?

A. Depending on the rate, either sample data or all available meter and billing data was utilized to develop the different load profiles. Residential and Commercial Secondary rates were all based on meter samples while Primary rates were based on all available actual data.

Q. Do the allocation schedules and load profiles used by the Company follow established industry COSS principles and methods?

A. Yes. The development of the schedules and load profiles follow industry recognized and accepted load research principles supported by the Edison Electric Institute and the Association of Edison Illuminating Companies. The Commission has consistently relied on these principles and methods in the past.

Q. How were the other input allocation schedules developed?

A. Allocation schedules 141-143, 150, 160, and 170 were developed using data supplied by Company witness Eugene M. Breuring and rate design inputs.

Q. How were the remaining allocation schedules developed?

A. In addition to the input allocation schedules, the COSS includes 55 calculated allocation schedules. The calculated allocation schedule numbers are shown on Exhibit A-16 (LMC-1), Schedule F-1, pages 10 through 15. The calculated allocation schedules were developed using data from the input schedules, the resulting assigned costs, and/or other information contained within the COSS.

III. TEST YEAR ELECTRIC COSS – VERSION 1

Q. What updates were made to Version 1 of the COSS?

A. The Company made routine updates for historic and test year data including updates to the allocation schedules discussed in Section II of my direct testimony. In some cases where

additional cost detail was provided by other Company witnesses, those costs were included in the Version 1 COSS and treated in a manner consistent with current approved methodologies. Version 1 of the COSS also incorporates a number of items that were approved in Case No. U-21389, the Company's most recent electric general rate case. The changes to Version 1 resulting from the order are:

- The breakout and allocation of battery plant and related costs;
- The breakout of the regulatory asset and amortization expenses for both PowerMIDrive ("PMD") and PowerMIFleet ("PMF") and allocation based on present revenues;
- Removal of the calculation of EIP credits in the COSS and movement/centralization of the calculation in Rate Design;
- Allocation methodologies for surcharges including the Electric Rate Case Deferral, IRM, and DR surcharges;
- Replacement of the current Class Peak allocator with an Alternative Class Peak to allocate demand-related distribution costs; and
- Continued breakout of certain Digital Customer Operations ("DCO") project costs.

In addition, the COSS – Version 1 reflects the removal of non-jurisdictional revenue as discussed by Company witness Josnelly C. Aponte. The LEDR revenue is being reflected in Miscellaneous revenue, in accordance with the development of the rate in Case No. U-21160. Exhibit A-16 (LMC-1), Schedule F-1, is a 40-page exhibit that summarizes the Test Year COSS – Version 1.

Q. How is the COSS treating the Regulatory Assets associated with D.E. Karn 1-2, Classic 7, and J. H. Campbell plants?

A. Consistent with current Commission approved methodologies, the rate base related to these assets, identified by Company witness Aponte in Exhibits A-19 (JCA-54) through A-25 (JCA-60), was functionalized as production and assigned to customers using allocator 220.

Q. Please describe the other allocations, approved by the Commission in Case No. U-21389, that were used to develop the Test Year Electric COSS – Version 1.

A. Production capacity costs were assigned to customers using allocator 220 which weights demand (the highest four CPs) by 75% and total energy by 25% ("4CP 75/0/25"). Production non-capacity costs were allocated on energy use at generation for the associated time periods and seasons. Transmission expense was allocated on 12 CP demand ("12 CP 100"). Distribution plant was primarily allocated on Class Peak demand[1] with related costs allocated in a similar manner as the associated plant. General, Common, and Intangible plant and related costs were allocated on labor. Working capital was primarily allocated on revenue, plant in service, and labor. Customer related and administrative and general expenses were primarily allocated on customer, revenue, and labor allocators. Property tax was allocated in a similar manner as the associated plant and income tax was primarily allocated on pretax net operating income.

Q. How is Exhibit A-16 (LMC-1), Schedule F-1, organized?

A. Across the top of page 1 are the classes on which the total cost to serve is allocated. Total Company electric information for the test year is found in column (c), while the MPSC jurisdictional information is shown in column (d), and non-jurisdictional information is

[1] Meter facilities and services are assigned using allocators based on the number of customers.

reported in column (j). Columns (e) through (i) show the distribution of the MPSC jurisdictional cost to serve each of the classes. The same information by rate schedule is found on pages 2 and 3. Pages 1 through 3 show rate base and net operating income in summary and by class. Pages 1 through 3, line 20, displays the revenue deficiency (sufficiency). Lines 24 through 28 breakout the revenue requirement reflected on line 23 by function. Pages 4 through 6 of Exhibit A-16 (LMC-1), Schedule F-1, show the development of total rate base, pages 7 through 9 detail the total electric Operations and Maintenance ("O&M") expense, and pages 10 through 15 list the allocation schedules.

Q. What is shown on pages 16 through 40 of Exhibit A-16 (LMC-1), Schedule F-1?

A. Pages 16 through 40 of Exhibit A-16 (LMC-1), Schedule F-1, show the line-item detail used to calculate the Proposed Rate Design Revenue and the allocators that were applied as required by the Schedule F-1 template included in the Commission's Standard Filing Requirements that were approved in Case No. U-18238.

Q. Is the Test Year COSS – Version 1 used for rate design purposes?

A. Yes. The Company is not including any proposals that would necessitate the need for a Version 2 COSS. Thus, the Test Year COSS – Version 1 is used for rate design purposes.

IV. SRM CAPACITY CHARGE CALCULATION

Q. Please describe Exhibit A-59 (LMC-2).

A. Exhibit A-59 (LMC-2) shows the calculation of the capacity-related costs and SRM Charge. To arrive at the total capacity-related costs (line 10), non-capacity related costs (line 9) are subtracted from total production costs (line 1) from the Test Year COSS. The total capacity-related costs (line 10) are then offset by the projected revenue and associated fuel cost (lines 12 through 18) sponsored by Company witness Megan L. Metz to arrive at

the net capacity cost (line 19). To arrive at the Capacity Charge, the net capacity cost (line 19) is divided by the demand provided by Company witness Metz (line 20). The resulting SRM Capacity Charge is $86.88 MW-Day.

The total non-capacity related cost (line 9), total revenue less fuel cost (line 18), and net capacity cost (line 19) from Exhibit A-60 (LMC-3), are the same values that appear in column (c), lines 24 through 26 of Exhibit A-16 (LMC-1), Schedule F-1. The rate design model uses these numbers to breakout capacity-related and non-capacity related power supply charges for full-service customers in accordance with the Commission's November 21, 2017 Order in Case No. U-18239.

V. SUBSTATION OWNERSHIP CREDIT CALCULATION

Q. Please describe Exhibit A-61 (LMC-4).

A. Exhibit A-61 (LMC-4) provides the calculation of the Substation Ownership Credit given to customers who own their own substations. The calculation, which follows the methodology approved by the Commission in Case No. U-18322, takes the substation costs that have been allocated to GPD, GPTU, and EIP customers on Voltage 1 and Voltage 2 and determines the cost on a per kW basis for each voltage level. The calculation follows the same methodology for both voltages using figures from Exhibit A-16 (LMC-1), Schedule F-1, Test Year COSS – Version 1 and rate design. Lines 1 through 5 list the different items included in the substation rate base, with the total substation rate base in line 6. The substation rate base is multiplied by the pre-tax return rate in line 7 to arrive at the pre-tax return in dollars in line 8. Various expenses (lines 9 through 11) and revenue credits (line 12) are added to the pre-tax return to arrive at the total substation revenue requirement by voltage in line 13. This total (in thousands of dollars) is divided by the

maximum demand in MW (line 14) from rate design to determine the Substation Ownership Credit in line 15.

VI. ALLOCATION OF SURCHARGES

Q. Please describe Exhibit A-16 (LMC-5), Schedule F-2.0.

A. Exhibit A-16 (LMC-5), Schedule F-2.0 shows the allocation, by rate class, for the proposed DR surcharge supported by Company witness Steven Q. McLean, the Electric Rate Case Deferral surcharge sponsored by Company witness Aponte, and the IRM surcharge sponsored by Company witness Heidi J. Myers. Exhibit A-16 (LMC-5), Schedule F-2.0 is used in rate design to calculate the surcharges.

Q. How is the Company proposing to allocate the DR surcharge?

A. DR costs have previously been allocated in the COSS using the production capacity allocator 220 (4CP 75/0/25). This treatment recognizes that DR is a capacity resource that is allocated in the same manner as other capacity costs. The Company is proposing to continue to allocate DR costs in this manner for the DR surcharge.

Q. How is the Company proposing to allocate the ERC Deferral surcharge?

A. The Company is proposing to allocate the ERC Deferral surcharge costs, which includes the cost of certain investment in the Company's distribution system, to each class in proportion to their share of total distribution costs in this case. This is the same method that was used in Case Nos. U-20697, U-21224, and U-21389.

Q. How is the Company proposing to allocate the IRM surcharge?

A. The Company is proposing to allocate the IRM surcharge costs, which includes the cost of certain investment in the Company's distribution system, to each class in proportion to

their share of total distribution costs in this case. This is the same treatment that the Company has used- and is proposing to continue using- for the ERC Deferral surcharge.

VII. RATE DESIGN OVERVIEW

Q. Please describe the primary objectives of rate design.

A. Consistent with the rate designs approved in prior cases, I used the following four key objectives to inform my rate design in this case. My first objective was to adhere to the cost of service in accordance with the requirements set forth in 2008 PA 286 ("Act 286"). I did deviate from the COSS in a couple instances and will further elaborate on my rationale for doing so later. My second objective was to design rates that encourage the efficient use of the Company's electric system. This means setting rates that accurately reflect the type of cost (fixed versus variable) as well as the temporal nature of certain costs, such as the increased cost of providing energy during peak seasons and times of day. My third objective was to design rates that promote a favorable business climate. For example, providing various rate structures and designs that encourage the location and expansion of business operations in the Company's service territory. My fourth objective was to design stable rates that provide the Company with a fair opportunity to collect its revenue requirement.

Q. Please describe the cost of service requirements set forth in Act 286.

A. Section 11 of Act 286 requires electric utilities to design rates that reflect the cost of providing service to each customer class. In other words, costs assigned to one class cannot be reassigned to another without cost justification. The intent being to prevent, or at the very least limit, interclass subsidies. However, this does not completely remove the utility's ability to maintain crossing-points between rates within a class and to make other

adjustments to deviate from the COSS in some instances. I have identified these deviations as adjustments to the class COSS in my Exhibit A-16 (LMC-6), Schedule F-2.1.

Q. Please describe your reasons for making these adjustments.

A. Consistent with prior electric rate cases, I am recommending five standard adjustments to the assignment of costs across the various rate classes and schedules as part of rate design. The first standard adjustment, shown on line 3 of Exhibit A-16 (LMC-6), Schedule F-2.1, reflects the difference between the market cost of production capacity collected from large standby customers taking service under Rate GSG-2 and the embedded cost of capacity allocated to them in the COSS. Two similar adjustments—the second and third—are made for both production energy and transmission costs, shown on lines 7 and 13, respectively. In total, these three adjustments suggest that large standby customers pay less under the market-based rate design structure for production and transmission standby service than they would under an embedded cost of service design. While this may warrant further evaluation in the event large standby services increase, I am not recommending any changes to the design of the Company's standby service Rate GSG-2 in this case.

The fourth standard adjustment, shown on line 18, is used to correct for an over allocation of substation costs to voltage levels 1 and 2 rates as part of the COSS. In the 2019 electric rate case, Case No. U-20134, it was brought to the Company's attention that it was inadvertently over allocating substation costs to the higher voltage level rates by excluding customer-owned substations from its COSS. To remedy the issue, the Company agreed to reassign the portion of substation costs by allocating those costs to customers who owned their substation in the COSS as part of rate design. The easiest way to

accomplish this was to allocate the substation ownership credits across the rate classes based on the distribution allocators developed in the COSS.

The last adjustment, shown on line 19, reflects the lifeline credits (senior citizen and low-income) that have traditionally been supported by all customer classes. Unlike the other approved adjustments, however, the lifeline adjustment is not cost justifiable. Instead, it is based on the Commission's authority to approve special senior citizen and low-income rates granted under Section 11 of Act 286.

Q. Are you recommending any new adjustments as part of the Company's rate design in this case?

A. Yes, the adjustment shown on line 2 of Exhibit A-16 (LMC-6), Schedule F-2.1, is a new line item that reflects the removal of the DR revenue requirement calculated by Company witness Aponte in Exhibit A-21 (JCA-56) and allocated to each rate schedule by Exhibit A-16 (LMC-5), Schedule F-2.0, from base rates. As described further by Company witness McLean and in the surcharge section of my testimony, the Company is again proposing to consolidate the DR program costs, customer credits, financial incentives, and regulatory balances in an all-encompassing surcharge. However, if the Commission rejects the proposal, then this adjustment is no longer necessary and should be removed.

Q. Please explain your approach in designing rates to collect the Company's production costs.

A. Production represents approximately two-thirds of the Company's cost of providing service and comprises both fixed and variable costs, which are separated in the COSS between capacity and energy costs. Production capacity represents the cost of a generating plant and having it stand ready to serve customer demand over an extended period of time

(annually) or at a certain hour (peak). Conversely, production energy represents the cost of running these plants and is usually attributed to fuel expenses. Traditionally, the Company has used a combination of historical prices based on the Midcontinent Independent System Operator, Inc. ("MISO") market to estimate the energy price spread of providing service during different time periods.

Q. Are you recommending any changes to the methodology used to calculate the production energy price spreads as part of the rate design?

A. No. Consistent with the method used in the prior electric rate case, Case No. U-21389, the Company is using the weighted average hourly Locational Marginal Pricing ("LMP") to calculate the energy charge spreads for the various Time-of-Use ("TOU") rates. This weighting of hourly LMP values based on the corresponding hourly energy use better reflects the value of energy in each time period.

Q. Please describe the calculation of the LTILRR revenues shown in your Confidential Exhibit A-65 (LMC-12).

A. The first page of Confidential Exhibit A-65 (LMC-12) contains the forecasted test year billing determinants and monthly charges based on the approved LTILRR tariff and customer contract. The second page of Confidential Exhibit A-65 (LMC-12) calculates the $99,370,432 of test year miscellaneous revenues, provided to Company witness Breuring, based on the information from the first page and the forecasted production and transmission costs sponsored by Company witness Metz.

Q. What happens if actual LTILRR electric sales are less than the level forecasted by the Company in this case?

A. Any changes in the electric sales and power supply costs associated with the LTILRR are included in the Company's annual PSCR plans and reconciliations. For example, if the actual LTILRR electric sales are lower than the levels forecasted in this case, then the Company would include the lower power supply miscellaneous revenue as part of the LTILRR payment in its PSCR reconciliation. Similarly, a higher sales level would result in a higher payment in the PSCR reconciliation.

Q. Is the Company recommending any changes to the LTILRR in this case?

A. No, it is not.

Q. Please describe the calculation of the LEDR revenues shown in your Confidential Exhibit A-66 (LMC-13).

A. In Case No. U-21160, the MPSC approved the LEDR tariff and inclusion of the related LEDR revenues in general rate cases as miscellaneous revenue. Confidential Exhibit A-66 (LMC-13) contains the forecasted test year billing determinants and monthly charges based on the approved LEDR tariff and forecasted customer usage during the test year. The calculated LEDR revenues are picked up by Company witness Breuring as part of total miscellaneous revenue in Exhibit A-15 (EMB-3), Schedule E-2.

VIII. RATE DESIGN PROPOSALS

A. Residential

Q. Please explain your approach in designing the Company's residential customer class rates.

A. The Company is recommending the Commission maintain the currently approved residential rate design structure. My overall objective in designing the residential rates was to continue providing a sense of stability for this class by maintaining the existing rate structures for each option—i.e. Residential Summer On-Peak Basic Rate ("RSP"), Residential Smart Hours Rate ("RSH"), Residential Nighttime Savers Rate ("RPM"), and Residential Service Secondary Non-Transmitting Meter Rate ("RSM"). There are no changes being proposed to the structure or type of charges. Also, the collection of charges within the available rate options were evaluated based on how each fit individually and collectively within the class. For example, the summer on-peak charges assessed in all three residential TOU options were set equal since each covered the same period and are intended to inform customers about the cost of providing power during that period.

Q. What is the residential monthly bill impact under your proposed rate design?

A. The average monthly residential customer bill is projected to increase 7.9% from approximately $127 per month to $137 per month. The monthly customer typical bill impacts for each rate schedule are also shown in my Exhibit A-16 (LMC-8), Schedule F-4.0.

Q. How does the residential monthly bill under your proposed rate design compare with the national average bill projected by the Energy Information Administration ("EIA")?

A. The national average residential electric bill from the EIA is projected to be $144 per month in 2025, which is approximately $7 more than the $137 per month projected for the Company's customers. The Company also offers customers various payment plans and ways to reduce their energy bills through its residential assistance, energy efficiency, and DR programs. In addition, customers interested in proactively managing their energy bills can use many of the programs and digital tools the Company provides; including the online energy dashboard and billing detail to understand how energy is used throughout the day, tips for reducing energy waste, bill forecast trends, and the rate advisor tool to identify actions that can be taken to reduce their bills.

B. <u>Secondary</u>

Q. Is the Company proposing any changes to the Secondary rate structure?

A. No, the Company is proposing to maintain its current rate structure for secondary customers.

Q. The final order in Case No. U-21389 directed the Company to work with Staff and other interested persons to develop and pilot alternative communication and TOU rate design structures for secondary commercial customers. Is the Company making a secondary TOU proposal in this filing?

A. While the Company did meet with Staff to discuss transitioning secondary customers to TOU rates, the Company is not prepared to make a proposal at this time. The Company understands that Staff prefers a two phase transition of all secondary customers on the

General Service ("GS") rate to a summer TOU rate, much like the Company's transition of residential customers to the RSP. The Company would like to spend more time understanding the customer segments within secondary class, their ability to shift usage, and the impact a TOU rate will have on them. The secondary customer class encompasses a wide range of customer types, from banks, auto repair shops, small health care centers to metal heat treating businesses. Many of these customers do not have the flexibility of residential customers to shift load and could see significant bill increases unless they significantly alter their business models. The Company will continue working with Staff on TOU solutions for customers within the secondary class and will look propose a solution in a future case.

C. Primary

Q. Is the Company proposing any changes to the Primary rate structure?

A. Yes. First, the Company is incorporating changes that were directed in the Final Order of Case No. U-21389. Next, the Company is proposing a new coincident peak energy provision for Rate GPD. The Company is also proposing to include a facilities allowance in Rate LEDR.

Q. Please describe the changes as ordered in Case No. U-21389.

A. The Final Order in Case No. U-21389 directed the Company to reduce the Rate EIP DR credit to 75% of Cost of New Entry ("CONE") in its next general rate case. The Company has reflected that in the proposed Rate EIP DR credit. In addition, the Final Order in Case No. U-21389 directed the Company to align the peak hours for Rate GPTU with Rate EIP. Company witness Breuring has reflected that change in his proposed determinants for Rate GPTU, which are used to develop the rate for Rate GPTU. Lastly, the Final Order directed

the Company to file an updated calculation of its DR credits in its next general rate case that include the latest estimate of CONE. Company witness McLean is addressing that in his testimony.

Q. Please explain the need for a coincident peak provision on Rate GPD.

A. Capacity costs on Rate GPD are collected through an On Peak Billing Demand charge. On Peak Billing Demand is based on the highest On Peak demand created during the billing month but never less than 60% of the highest On Peak billing demand of the four preceding summer billing months (this is generally referred to as a demand ratchet). The On Peak Billing period is defined as 11 AM to 7 PM. There are unique circumstances where customers might run production during the Off Peak hours and avoid the On Peak window to keep costs low. In the event their production was delayed and ran into the On Peak window in the summer, they would be charged for 60% of that On Peak demand for the next eleven months. This can have a huge impact on the bill of a customer that is trying to respond to price signals to keep their bill low. The coincident peak provision is proposed as a solution to help this very specific type of customer.

Q. Please describe how the coincident peak provision works.

A. The coincident peak provision on Rate GPD is designed to collect On Peak capacity and transmission on an energy basis rather than on a demand basis. A customer on this provision would pay the same On Peak and Off Peak energy charges, customer charges, and distribution charges as a standard GPD customer. The On Peak capacity and transmission charges were converted from a per kW basis to a per kWh basis and would be charged for any usage during the On Peak period. This allows a customer on the provision to use into the On Peak period without triggering the On Peak demand ratchet.

However, if the customer will be charged the On Peak demand charges if they use during the coincident peak window of 4 PM to 6 PM. In exchange for the benefit of avoiding setting an On Peak demand ratchet, a customer on this provision agrees to be subject to critical peak pricing events. To the extent an event is called, the customer will pay the full On Peak demand charge plus $1.00/ kWh for any energy used during the event. Subjecting the customers on the provision to On Peak demand charges during the coincident peak window of 4 PM to 6 PM and to critical peak pricing provides clear and direct price signals to avoid using during peak times of the month.

Q. Is the proposed coincident peak provision open to all customers?

A. The Company is proposing to limit the provision to three customers so the impact can be evaluated. Because this provision would only benefit a customer that uses primarily Off Peak, the Company does not expect a high customer interest in the provision. Due to the limited nature of the proposal, the Company did not forecast any determinants on the provision at this time.

Q. Please describe the Company's proposal to include a facilities allowance with the Large Economic Development rate.

A. The Large Economic Development Rate was first established by the Commission in Case No. U-21160 and implemented in December 2021. There has been robust interest in the rate and many potential customers have inquired about the availability of a facilities allowance such as that offered under DTE Electric Company's Rate D13. To better align with other cost-based large customer rate options in Michigan, the Company is proposing to add language to the tariff that would clarify a facilities allowance would be applicable for customers on the rate.

Q. Please describe the Company's proposed method for calculating the facilities allowance for customers.

A. The Company is proposing to calculate the facilities allowance for each prospective customer based on the net present value of margin – defined as the non-energy related costs – based on their expected load over the life of the contract.

Q. Do LEDR customers provide the same level of contribution to embedded cost as a normal bundled customer?

A. No. Because Rate LEDR is based on the marginal cost of serving new load, customers on the rate do not provide the same level of contribution to embedded costs but they contribute to the embedded costs through the system contribution charge that is part of the rate.

Q. Would excluding the power supply costs from the calculation of the net present value of margin used to determine the facilities allowance result in an allowance that is competitive with the allowance DTE is able to offer customers on its Rate D13?

A. No. DTE's Rate D13 provides a facilities allowance that includes power supply revenues and thus would result in a more competitive offering.

Q. Does attracting new load to the Company's LEDR rate offer other benefits to customers?

A. Yes. As noted above, the revenue from LEDR is included as part of miscellaneous revenue which is allocated to all rate schedules and lowers the revenue requirement in the rate case, thereby lowering rates. In addition, attracting large companies to Michigan can provide transformational opportunities, included jobs, tax revenue, infrastructure, new residences, and quality of life improvements.

D. Lighting

Q. Is the Company proposing any change to the streetlighting rate structures?

A. No, the Company is proposing to maintain the current rate structure for Rate GSG-2.

E. Self-Generation

Q. Is the Company proposing any change to the Self-Generation rate structure?

A. No, the Company is proposing to maintain the current rate structure for Rate GSG-2.

F. Power Factor

Q. Is the Company proposing any change to the existing Power Factor credit and penalty structure?

A. Yes. The Settlement Order in Case No. U-21224 directed the Company to develop a report on issues pertaining to the impact of power customer power factor associated with Rates GSD, GP, GPD, GPTU, EIP, and GSG-2. In response to findings in that report and meetings with the interested parties, the Company is proposing a change to the application of power factor credits and penalties.

Q. Please describe power factor.

A. Power factor is defined as the ratio of "real" resistive power (kilowatts) to "apparent" supplied power (kilovolt-amperes). Power factor adjustments reflect the impedance that reactive devices, such as electric motors, induce on our system. All things being equal, customers with lower power factors require more investment in generation, transmission, and distribution capacity than other customers of similar size.

Q. How are power factor credits and penalties assessed today?

A. The average power factor is determined through metering of lagging Kilovar-hours and Kilowatt-hours during the billing period. The calculated ratio of lagging Kilovar-hours to

Kilowatt-hours is converted to an average power factor for the billing factor. Consumers Energy's current tariff assesses a power factor credit of 0.50% applied to all metered-based charges excluding surcharges, for an average power factor of 0.900 or higher. A power factor penalty is assessed based on a percentage of all metered charges, excluding charges when an average power factor is less than 0.850, varying based on the table below:

Power Factor	Penalty Percentage
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

In addition, the current tariff states that a power factor less than 0.700 is not permitted and assesses a 15% penalty to any metered based charges, excluding surcharges, after two consecutive months below 0.700 power factor and continues if the power factor remains below 0.700.

Q. What change is the Company proposing to the application of power factor penalties and credits?

A. The Company is proposing to compare the average hourly metered kilovolt-ampere reactive hour (kVARh) for the month to the average hourly kVARh at 0.875 lagging power factor. The difference between these two values would determine the average kilovolt-ampere reactive (kVAR) demand of underperformance or overperformance for the month. This average kVAR demand of underperformance (penalty) or overperformance (credit) would be subject to a monthly per kVAR charge. The per kVAR charge is calculated so as not to dramatically change what is being applied today.

Q. Please describe Exhibit A-67 (LMC-14)

A. Column (a) calculates the excess kVARh for customers with an average power factor at or above 0.875 based on 2023 actual usage and kVARh data. From there, the power factor charge was determined based on the actual power factor credit revenue from 2023. The proposed power factor charge is $1.14 per kilovar. The same $1.14 per kilovar was then applied to the excess kVARh for customers with a power factor below 0.875 but above 0.700 to determine the penalty revenue in column (b). The calculated credit revenue from column (a) and penalty revenue in column (b) was then compared to the actual power factor revenue in 2023. The difference was used to calculate a power factor penalty for accounts with power factor below 0.700. The proposal is to continue to allow customers with a power factor below 0.700 a two-month period to correct their power factor. After that, these customers would be subject to a charge of $5.25 per kilovar. The proposed charges and application of power factor are also explained in the applicable tariff sheets as part of Exhibit A-16 (BAG-2), Schedule F-5.

G. Direct Current Fast Charger Tariff Directive

Q. The Final Order in Case No. U-21389 directed the Company to conduct a load shape study for Direct Current Fast Charges ("DCFCs") as well as Level 2 chargers and to evaluate whether it is appropriate for these chargers to have separate tariffs. Is the Company proposing a separate tariff for DCFC and/or Level 2 chargers at this time?

A. No. As discussed by Company witness Jeffrey A. Myrom, the Company is still gathering data to understand the load shape of both DCFCs and Level 2 chargers. The population of these chargers is still relatively small, and the utilization of the chargers is quite limited.

To propose a separate tariff at this time would be premature. Consumers Energy will continue to evaluate the data and determine if a separate tariff is appropriate in the future.

IX. SURCHARGES

Q. Please describe the method used to develop the DR surcharge proposed by Company witness McLean.

A. As discussed by Company witness McLean, the Company is again proposing to improve the DR reconciliation process by collecting the program revenue requirement, customer credits, residual balances from the reconciliation cases, and financial incentives in an all-encompassing surcharge. The DR program costs, financial incentive, and reconciled balance of $50,506,000 is calculated by Company witness Aponte in Exhibit A-29 (JCA-64) as a revenue requirement and allocated to the various rates in Exhibit A-61 (LMC-4). The removal of the DR revenue requirement from base rates is shown in Exhibit A-16 (LMC-6), Schedule F-2.1, line 2, and the corresponding DR surcharge to collect the test year DR revenue requirement and customer credits is shown on line 23 in the same exhibit.

Q. Please describe why the DR surcharge shown on line 23 of Exhibit A-16 (LMC-6), Schedule F-2.1, exceeds the DR revenue requirement shown on line 2 of the exhibit.

A. The Company had introduced the idea of having a DR surcharge to recover the program costs, financial incentive, and reconciled balance in a prior electric rate case, Case No. U-20963. But as part of the case, Staff had expressed interest in having the surcharge also include the tariff based bill credits associated with the residential and business DR programs. The $8,572,000 difference between the $50,506,000 revenue requirement

calculated by Company witness Aponte and the $59,078,000 being recovered through the surcharge are the tariff bill credits.

Q. Please describe the method used to design the ERC Deferral surcharge in this case.

A. As discussed by Company witness Aponte, the Company is proposing an ERC Deferral surcharge to recover $21,811,000 of deferred distribution investments. Similar to the existing surcharge, the deferred costs were allocated to the various rates in Exhibit A-61 (LMC-4) and divided by the test year sales to calculate the surcharge.

Q. Describe the IRM proposed by the Company.

A. The proposed IRM would authorize the Company to collect additional revenues associated with incremental distribution reliability spending beginning March 1, 2025 through February 28, 2028, as discussed in the testimony of Company witnesses Myers and Kelly.

Q. Please describe Exhibit A-64 (LMC-11).

A. Exhibit A-64 (LMC-11) is an illustrative calculation of the proposed IRM surcharge. It shows how the Company proposes to collect the revenue requirements associated with the IRM. As shown on the exhibit, the revenue requirements associated with the IRM are based on a demand or energy surcharge for each of the rate schedules. The revenue requirements for each class are based on the cost allocation of the revenue requirements in Exhibit A-61 (LMC-4). The rate design for the various voltage levels for Rates GP, GPD, EIP, and GPTU are consistent with the rate differentials used in the Company's rate design. The surcharge is based on test year sales and would apply to both Full Service and ROA customers. With approval of the Commission, these rates would be effective for service rendered on and after March 1, 2025. The IRM surcharges would continue until rates were modified in the Company's next electric case.

Q. How does the Company propose to reconcile the IRM?

A. As discussed in the testimony of Company witness Myers, the reconciliation of the IRM would be handled in a separate contested proceeding. The Company proposes to reconcile the IRM capital spend on an annual basis. The reconciliation would compare the Company's annual IRM revenue requirement based on the actual incremental investments for that 12-month period against the associated revenue requirement collected from customers by class for that year through the IRM surcharge. If, for example, the actual IRM revenue requirement fell short of the Commission-approved amount collected through the surcharge, then the Company would refund customers the difference.

Q. Would the Company be allowed to increase the surcharges over the amount the Commission approved in a final order in this case?

A. No. The Company would only be authorized to implement the surcharges approved by the Commission in this proceeding. However, the Company would implement reductions as ordered by the Commission to modify the surcharge if the amount of the investment was less than the total incremental investment proposed spend amount.

Q. Does this conclude your direct testimony?

A. Yes.

Consumers Energy
Count on Us

October 17, 2023

Ms. Lisa Felice
Executive Secretary
Michigan Public Service Commission
7109 West Saginaw Highway
Post Office Box 30221
Lansing, MI 48909

RE: Case No. U-21224 – In the matter of the application of Consumers Energy Company for authority to increase its rates for the generation and distribution of electricity and for other relief.

Dear Ms. Felice:

Enclosed for electronic filing in the above-captioned case, please find the **Consumers Energy Company's Power Factor Report**.

This is a paperless filing and is therefore being filed only in PDF. I have included a Proof of Service showing electronic service upon the parties.

Sincerely,

Digitally signed by
Gary A. Gensch, Jr.
Date: 2023.10.17
11:01:21 -04'00'

Gary A. Gensch Jr.
Phone: 517-788-0698
Email: gary.genschjr@cmsenergy.com

cc: Parties per Attachment 1 to Proof of Service

Consumers Energy Power Factor Report

Background

In the settlement agreement approved January 19, 2023 in Case No. U-21224, the parties to the case agreed to the following:

"Within nine months of the final order in the proceeding, Consumers Energy will develop a report on issues pertaining to the impact of poor customer power factor associated with Rates GSD, GP, GPD, GPTU, EIP, and GSG-2. Consumers Energy will provide Staff, ABATE, and other interested parties the opportunity for meaningful input with respect to the development of the report. After completion of the report, Consumers Energy will meet with Staff, ABATE, and other interested parties to discuss the results and the most appropriate way to structure the power factor correction charges and credits applicable to large customers to reflect the impact."
MPSC Case No. U-21224 December 22, 2022 Settlement Agreement (Pages 9 – 10)

Power factor is defined as the ratio of "real" resistive power (kilowatts) to "apparent" supplied power (kilovolt-amperes). Power factor adjustments reflect the impedance that reactive devices, such as electric motors, induce on our system. All things being equal, customers with lower power factors require more investment in generation, transmission, and distribution capacity than other customers of similar size.

Average power factor is determined through metering of lagging Kilovar-hours and Kilowatt-hours during the billing period. The calculated ratio of lagging Kilovar-hours to Kilowatt-hours is converted to an average power factor for the billing factor. Consumers Energy's current tariff assesses a power factor credit of 0.50% applied to all metered-based charges excluding surcharges, for an average power factor of 0.900 or higher. A power factor penalty is assessed based on a percentage of all metered charges, excluding charges when average power factor is less than 0.850, varying based on the table below:

Power Factor	Penalty Percentage
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

In addition, the current tariff states that power factor less than 0.700 is not permitted and assesses a 15% penalty to any metered-based charges, excluding surcharges, after two consecutive months below 0.700 power factor and continues as long as the power factor remains below 0.700.

Discussion

Consumers Energy ("CE") held four stakeholder meetings with the Michigan Public Service Commission ("MPSC") Staff, the Association of Businesses Advocating Tariff Equity ("ABATE"), and Hemlock Semiconductor Operations ("HSC"). In the first meeting, we discussed the current methodology for rewarding/penalizing customers for power factor and gathered ideas from the group on other potential methodologies. In the second meeting, CE presented an overview of current methods used by peer utilities to reward/penalize customers for power factor and the group continued to brainstorm appropriate methodologies. In that meeting, ABATE committed to provide a straw proposal for the team to react to. In the third meeting, CE presented the costs of serving poor power factor customers on the high voltage distribution ("HVD") and low voltage distribution ("LVD") systems and ABATE reviewed their straw proposal. In the fourth and final meeting, the team discussed ideal power factor and reviewed customer impacts based on the straw proposal.

In brainstorming at the first session, ABATE took the position that power factor rewards/penalties should be applied equally to bundled and retail open access ("ROA") customers since the impact of poor or superior power factor by both sets of customers on CE's costs is identical. In addition, ABATE noted the costs for correcting poor power factors are predominately related to equipment added to the distribution system – such as capacitors – and so are independent of the generation provider. ABATE suggested that moving away from a percentage adjustment to per kW and per kWh rates for poor or superior power factor to a per kVar adjustment for poor or superior power factor better reflected cost causation. Staff thought improving power factor had benefits and costs beyond distribution, and so felt any rewards/penalties should include both a power supply and delivery component.

After the first meeting, ABATE followed up with the team to expand on the power supply versus distribution discussion. ABATE shared that for production costs, regardless of whether the poor power factor is from a bundled customer or an ROA customer, uncorrected poor power factor has the effect of: (i) increasing the transmission loss factor used in the Midcontinent Independent System Operator, Inc. ("MISO") Planning Resource Auction to determine the Planning Reserve Margin Requirement ("PRMR") for all load within CE Local Balancing Authority Area ("LBA") within MISO and (ii) increasing the Marginal Losses Component ("MLC") of the Locational Marginal Price ("LMP") in the MISO day-ahead and real-time energy markets for the CE load zone within MISO. As a result, the impact on CE's production costs is to: (i) increase CE's PRMR (i.e., MISO capacity requirement) to serve all of its bundled customers and (ii) increase the market price for settling the energy consumption for all of CE's bundled customers in the MISO day-ahead and real-time energy markets. This effect is the same regardless of whether the poor power factor that was not corrected for with capacitor banks or other kVAR producing device investments was from a bundled customer or an ROA customer.

At the May 16 meeting of the study group, CE provided the preliminary results of research it conducted into the approach used by neighboring utilities with respect to large customer power factor performance. Those preliminary results showed that most utilities encouraged customers to improve their power factor through either a percentage adjustment on their monthly bill or a kVAR charge/credit. The group also continued the discussion on the difference between correcting for poor power factor on a bundled customer compared to an ROA customer. CE discussed how it makes capacitor bank improvements at both the LVD and HVD levels on the distribution system to correct total system power factor. This is done regardless of whether the customers being served are full service or ROA. Given this, ABATE offered to put together a straw proposal modeling a kVAR based approach. CE also committed to providing the costs of power factor correction at its next meeting.

The team met for a third time on August 17 and discussed the costs of correcting for power factor and reviewed ABATE's straw proposal. CE shared that the costs vary based on the capacitor size and the cost per kVar increases as the capacitor size decreases. LVD power factor correction is typically done at the pole top while HVD correction is done at the substation. There are various factors at play to determine the type of correction and capacitor size. The capacitors also need to be maintained but the cost of maintenance is not easily isolated as the maintenance is typically done as part of routine inspection and maintenance work on the system. In addition, because we look at system as a whole for reactive compensation, installing capacitors on the HVD system inherently supports the LVD system as well.

ABATE then reviewed their straw proposal which is summarized as follows:

ABATE's Straw Proposal is to maintain CE's current power factor provisions for GSD, GP, GPD, GPTU, EIP and GSG-2 as is, except for the following:

- Instead of an escalating penalty equal to a percentage of the customer's total non-surcharge power supply charges and distribution charges, a per kVAR penalty applicable to the average lagging reactive kVAR of the customer in excess of 0.875 lagging power factor would apply.

- Instead of a credit equal to a percentage of the customer's total non-surcharge power supply charges and distribution charges that applies when a customer's lagging power factor is 0.875 or higher, a per kVAR credit applicable to the average lagging reactive kVAR of the customer below that for 0.875 lagging power factor would apply.

- The charge that applies to the customer's average system kVAR in excess of 0.875 lagging power factor when a customer's power factor is between 0.700 and 0.874 lagging would be set at the estimated monthly levelized per kVAR cost of a new distribution capacitor

bank. At a $100 per kVAR total installed cost, that would be approximately $0.80 per kVAR.[1]

- The credit that applies to the customer's average system kVAR below 0.875 lagging power factor would be of the same value as the levelized per kVAR charge that applies to kVAR in excess of 0.875 lagging power factor when a customer's power factor is between 0.700 and 0.874 lagging.

- Below 0.700 lagging power factor, for the first two months the same kVAR charge would apply as applies when a customer's lagging power factor falls between 0.700 and 0.874. However, after the first two months, the charge would increase to ten times the kVAR charge that applies to a customer with an average lagging power factor of between 0.700 and 0.874.

The Straw Proposal would apply the same per kVAR credits and penalties to both bundled customers and ROA customers and those credits and penalties would have a cost basis by being founded on the per unit marginal cost to install additional distribution capacitor banks.

The parties were agreeable to the kVAR approach, expressing that it aligns with standard practice at other utilities and equitably assesses power factor penalties/credits to bundled and ROA customers. The team wanted to see example customer impacts and expressed that the results should not be substantially different from how customers are treated today.

At the fourth and final meeting, the team reviewed the example customer rate impacts and discussed other nuances of the kVAR approach. This included considerations around including both HVD and LVD costs in the development of the power factor charge and how to set the appropriate multiplier for customers with continually poor power factor.

Conclusions

While there are multiple ways to address power factor, the stakeholders agree that applying penalties and credits on a KVAR basis is a reasonable approach. It provides for equitable treatment for both bundled and ROA customers and can be feasibly implemented in the billing system. When determining the appropriate charge/credit, cost of correction for both HVD and LVD should be considered as CE corrects for power factor based on the system as a whole. This charge/credit should also consider maintenance costs and should be based on the revenue requirement of the corrections costs in order to come up with a levelized factor. Any proposal should be compared to current so as not to dramatically change the penalties and credits assessed. The same is true for determining what multiplier should be applied to customers with a power factor below 0.700 for more than two consecutive months. Any changes made to the

[1] Assuming a 10% fixed charge rate, $0.80 per kVAR ≈ $100 per kVAR x 10% / 12 months.

existing power factor construct will need to be approved by the MPSC. While there was consensus on the discussion and approach in this report, this does not tie any party to support in a future case filing.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the generation and distribution of electricity and for other relief.	))))))	Case No. U-21224

PROOF OF SERVICE

STATE OF MICHIGAN)
) SS
COUNTY OF JACKSON)

Melissa K. Harris, being first duly sworn, deposes and says that she is employed in the Legal Department of Consumers Energy Company; that on October 17, 2023, she served an electronic copy of the **Consumers Energy Company's Power Factor Report** upon the persons listed in Attachment 1 hereto, at the e-mail addresses listed therein.

Melissa K. Harris

Subscribed and sworn to before me this 17th day of October 2023.

Crystal L. Chacon

Crystal L. Chacon, Notary Public
State of Michigan, County of Ingham
My Commission Expires: 05/25/24
Acting in the County of Eaton

ATTACHMENT 1 TO CASE NO. U-21224

Party	Mailing Address	Email Address
Please serve all documents on mpsc.filings@cmsenergy.com as well as the attorneys appearing in this case.		
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ATTACHMENT 1 TO CASE NO. U-21224

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ATTACHMENT 1 TO CASE NO. U-21224

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Counsel for Michigan Electric Transmission Company LLC		
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* Receives Confidential Materials

ATTACHMENT 1 TO CASE NO. U-21224

Counsel for Michigan Municipal Association for Utility Issues		
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* Receives Confidential Materials

Question:

2. Ms. Connolly maintains that the proposed Power Factor penalty designed for Rate LED is in part needed to assist the Company to maintain compliance with the Power Factor requirements outlined in the Distribution-Transmission Interconnection Agreement ("DTIA") with Michigan Electric Transmission Company ("METC"), filed at the Federal Energy Regulatory Commission ("FERC"). She states that these DTIA Power Factor requirements require Consumers to maintain a 98% Power Factor for Consumers' load. Concerning this testimony, please provide the following, including all calculations on electric spreadsheet format with all formulas and links intact:

a. Consumers' load Power Factor under the DTIA without a new Rate LED customer.

b. Consumers' load Power Factor under the DTIA assuming a new 50 MW Rate LED customer that operates at an 85% Power Factor.

c. Consumers' load Power Factor under the DTIA assuming a new 50 MW Rate LED customer that operates at an 80% Power Factor.

d. Please estimate the cost or penalty to Consumers under the DTIA based on its load Power Factor estimated for items a., b., and c., above.

e. Please estimate the power factor penalty payment that the Rate LED customer would make to Consumers in items b. and c. above.

f. Please provide a copy of, or a link to, the DTIA.

Response:

a. Consumers' current system aggregated Power Factor at all interconnection points to the transmission system at system peak conditions is estimated to be 0.9977.
b. Consumers' system aggregated Power Factor at all interconnection points to the transmission system at system peak conditions assuming a new 50 MW customer operating at 85% Power Factor without power factor correction is estimated to be 0.9974.
c. Consumers' system aggregated Power Factor at all interconnection points to the transmission system at system peak conditions assuming a new 50 MW customer operating at 85% Power Factor without power factor correction is estimated to be 0.9973.
d. Under current system loadings, the Company would not incur a cost or penalty under the DTIA for a singular new 50 MW customer.
e. Please see response to U21870-SLT-CE-240.
f. Please see attached

Witness: Laura M. Connolly
Date: August 25, 2025

A FORTIS COMPANY

January 7, 2025

VIA ELECTRONIC FILING

The Honorable Debbie-Anne Reese
Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426

Re: Michigan Electric Transmission Company, LLC
Consumers Energy Company
FERC Docket No. ER25-___-000
Filing of Amended and Restated Distribution-Transmission Interconnection Agreement

Dear Secretary Reese:

Pursuant to section 205 of the Federal Power Act ("FPA"), 16 U.S.C. § 824d (2012), and Section 35.13 of the Federal Energy Regulatory Commission's ("FERC" or "Commission") regulations, 18 C.F.R. § 35.13 (2024), Michigan Electric Transmission Company ("METC") and Consumers Energy Company ("Consumers Energy") (METC and Consumers Energy are referred to herein individually as a "Party" and collectively as the "Parties") hereby respectfully submit an executed Amended and Restated Distribution-Transmission Interconnection Agreement ("DTIA"). The DTIA has been designated as the Eleventh Revised Service Agreement No. 1926 under the Midcontinent Independent System Operator, Inc. ("MISO")[1] FERC Electric Tariff, Fifth Revised Vol. No. 1 ("Tariff").

The Parties are revising the DTIA to update certain exhibits. The Parties respectfully request that the Commission accept the revised DTIA effective January 1, 2025.

I. INTRODUCTION

A. Background of the DTIA

In 2001, in response to Michigan electric restructuring initiatives, Consumers Energy vertically disaggregated its electric business and divested its transmission facilities into a subsidiary. The scope of the transmission facilities Consumers Energy divested was approved by the Michigan Public Service Commission ("MPSC") in an asset classification proceeding utilizing

[1] As administrator of the MISO Tariff, MISO joins METC and Consumers Energy in this filing of service agreements under the MISO Tariff, but takes no position on the substance of the filing.

Order No. 888's Seven Factor Test.[2] The Commission conditionally authorized a proposed intra-corporate asset transfer of substantially all of Consumers Energy's transmission facilities with voltage ratings of 120 kV and above to a wholly-owned subsidiary of Consumers Energy.[3] Effective May 1, 2002, and as approved by the Commission in Docket No. EC02-23, METC acquired ownership of the transmission facilities previously spun down to Consumers Energy's subsidiary.[4] In that proceeding, Consumers Energy proposed to exit the transmission business and become a local distribution company, while the applicants asserted that METC would operate solely as an independent transmission company.[5] At the time, METC was owned by Trans-Elect, Inc. and intermediate parent companies. METC is now a wholly-owned subsidiary of ITC Holdings Corp., which in turn is majority owned by Fortis Inc. and minority owned by GIC Private Limited. METC's transmission facilities are located in the Lower Peninsula of Michigan, and transmission service across METC's transmission facilities is provided pursuant to the MISO Tariff.

The original DTIA was submitted to the Commission for approval as part of the Docket No. EC02-23 proceeding. Broadly, the DTIA is intended to facilitate the coordinated operation of METC's transmission system and Consumers Energy's distribution system. In particular, the DTIA "define[s] the continuing rights, responsibilities, and obligations of" the Transmission Owner (METC) and the Local Distribution Company (Consumers Energy) "with respect to the use of certain of their own and the other Party's property, assets, and facilities."[6] Section 3.4 of the prior DTIA established the Parties' agreement that the principles upon which the initial classification of assets as either transmission or distribution shall continue to be applied, and that "[s]hould future system modifications result in the reclassification of assets, the Parties agree to convey ownership of those assets to the appropriate Party."[7] The Parties also entered into an Operating Agreement governing Consumers Energy's role as "Local Distribution Company" and METC's role as "Transmission Provider," which requires METC to provide transmission service

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2 *Consumers Energy Co.*, Docket No. U-11283 (Mich. Pub. Serv. Comm'n Jan. 14, 1998). FERC approved this MPSC asset classification determination in a July 29, 1998 Letter Order in Docket No. EL98-21.

3 *Consumers Energy Co.*, 94 FERC ¶ 61,018, at 61,031 (2001).

4 *Trans-Elect, Inc.*, 98 FERC ¶ 61,142, *order on reh'g*, 98 FERC ¶ 61,386 (2002). Commission staff also has accepted several revisions to the DTIA. *See Midwest Indep. Transmission Sys. Operator, Inc.*, Docket No. ER10-2501-000 (Oct. 6, 2010) (delegated letter order); *Midwest Indep. Transmission Sys. Operator, Inc.*, Docket No. ER12-1873-000 (July 3, 2012) (delegated letter order); *Midwest Indep. Transmission Sys. Operator, Inc.*, Docket Nos. ER12-1873-001, *et al.* (Sept. 25, 2012) (delegated letter order); *Midwest Indep Transmission Sys. Operator, Inc.*, Docket No. ER13-636-000 (Feb. 14, 2013) (delegated letter order); *Midwest Indep. Transmissions Sys. Operator, Inc.*, Docket No. ER15-611-001 (Mar. 24, 2015) (delegated letter order).

5 *See* Mich. Elec. Transmission Co., LLC, Application, Docket No. EC06-27-000, at 7 (filed Nov. 10, 2005); *Mich. Elec. Transmission Co., LLC*, 113 FERC ¶ 62,220 (2005).

6 DTIA at Recitals.

7 *Id.* at Section 3.4.

to Consumers Energy's loads and resources and obligates METC to construct transmission facilities for the purpose of providing such service. The DTIA has been revised from time to time to reflect changes between the Parties.[8] The Parties are further revising the DTIA as described below.

II. DESCRIPTION OF FILING

A. DTIA

The Parties are revising the DTIA to reflect changes to several exhibits and other minor ministerial and housekeeping changes. The changes are described below:

Exhibit 1 – Interconnection Points (Substations)

- Updated heading to "Addendum 14 - October 18, 2024".
- Added the following substation:
  - Alliance (05/24)
  - Celery (03/24)
  - Charge (05/24)
  - Riverbend (12/24)
  - Santiago (12//24)
- Removed the following substation(s):
  - Morrow

Exhibit 6 – Joint Owned Assets Ownership by Percent of Major Equipment

- Updated heading to "Addendum 14 – Final October 18, 2024".
- Updated ownership percentages for the following substations:
  - Dort
  - Four Mile
  - Morrow (Removed)
  - Twining (Removed)

III. DOCUMENTS SUBMITTED IN THIS FILING

The documents being submitted with this filing include the following, in addition to this transmittal letter:

Tab A - Clean copy of the DTIA; and
Tab B - Redline comparison of the DTIA to the Tenth Revised DTIA.

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[8] *See, e.g., Michigan Electric Transmission Company, LLC and Consumers Energy Company*, Docket No. ER20-2531-000 (filed July 29, 2020); Letter Order accepting filing August 28, 2020; *Michigan Electric Transmission Company, LLC and Consumers Energy Company*, Docket No. ER22-929-000 (filed January 31, 2022); Letter Order accepting filing March 11, 2022.

IV. PROPOSED EFFECTIVE DATE

The Parties respectfully request that the Commission accept the proposed revisions effective January 1, 2025.

The Parties request waiver of any part of Part 35 of the Commission's regulations not completely satisfied by this filing.

V. COMMUNICATIONS

Correspondence and service regarding this filing should be addressed to the following persons:

METC
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Counsel - Regulatory & Legislative
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Novi, MI 48377
Tel: (248) 946-3000
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Consumers Energy
Emerson J. Hilton
Assistant General Counsel
Consumers Energy Company
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Jackson, MI 49201
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emerson.hilton@cmsenergy.com

V. NOTICE AND SERVICE

MISO notes that it has served a copy of this filing electronically, including attachments, upon all Tariff Customers under the Tariff, MISO Members, Member representatives of Transmission Owners and Non-Transmission Owners, as well as all state commissions within the Region. The filing has been posted electronically on MISO's website at https://www.misoenergy.org/legal/ferc-filings/ for other interested parties in this matter. In addition, MISO has served a copy of this filing electronically on all parties to this agreement.

VI. CONCLUSION

For all the foregoing reasons, the Parties respectfully request that the Commission accept the DTIA to be effective January 1, 2025.

Respectfully submitted,

For METC:

/s/ Lauren Parrottino
Lauren Parrottino
Counsel - Regulatory & Legislative
ITC Holdings Corp.
27175 Energy Way
Novi, MI 48377
Tel: (248) 946-3000

For Consumers Energy:

/s/ Emerson J. Hilton
Emerson J. Hilton
Assistant General Counsel
Consumers Energy Company
One Energy Plaza
Jackson, MI 49201
Tel: (517) 788-1241

TAB A

SA 1926 METC-CE DTIA VERSION 39.0.0

EFFECTIVE 1/1/2025

ELEVENTH REVISED SERVICE AGREEMENT NO. 1926

AMENDED AND RESTATED DISTRIBUTION-TRANSMISSION INTERCONNECTION AGREEMENT

by and between

Michigan Electric Transmission Company, LLC

as Transmission Provider

and

Consumers Energy Company

as Local Distribution Company

AMENDED AND RESTATED DISTRIBUTION-TRANSMISSION INTERCONNECTION AGREEMENT

by and between

Michigan Electric Transmission Company, LLC

as Transmission Owner

and

Consumers Energy Company

as Local Distribution Company

Document Accession #: 20250107-5024 Filed Date: 01/07/2025

TABLE OF CONTENTS

AMENDED AND RESTATED

DISTRIBUTION TRANSMISSION INTERCONNECTION AGREEMENT

This Amended and Restated Distribution Transmission Interconnection Agreement ("Agreement") is entered into by and between the Michigan Electric Transmission Company, LLC, a Michigan limited liability company ("Transmission Owner"), having a place of business at 27175 Energy Way, Novi, Michigan 48377, and Consumers Energy Company ("Local Distribution Company"), a Michigan company, doing business in Michigan and having a place of business at One Energy Plaza, Jackson, Michigan, 49201. Transmission Owner and Local Distribution Company are individually referred to herein as a "Party" and collectively as "Parties." This Agreement amends, restates and completely replaces any and all previous versions of the Distribution Transmission Interconnection Agreement between the Parties, and is effective as of January 1, 2025.

WHEREAS, Transmission Owner requires access to parts of Local Distribution Company's assets, and Local Distribution Company requires access to parts of Transmission Owner's assets; and

WHEREAS, the Parties have agreed to execute this mutually acceptable Agreement in order to provide interconnection of the Local Distribution Company with the Transmission Owner and to define the continuing rights, responsibilities, and obligations of the Parties with respect to the use of certain of their own and the other Party's property, assets, and facilities.

NOW, THEREFORE, in consideration of their respective commitments set forth herein, and intending to be legally bound hereby, the Parties covenant and agree as follows:

ARTICLE 1. Definitions

Wherever used in this Agreement with initial capitalization, the following terms shall have the meanings specified or referred to in this Article 1.

1.1 Administrative Committee means the committee established pursuant to Article 6 of the Operating Agreement dated April 1, 2001, as amended and restated, between Local Distribution Company and Transmission Owner.

1.2 Agreement means this Interconnection Agreement between Local Distribution Company and Transmission Owner, including all attachments hereto, as the same may be amended, supplemented, or modified in accordance with its terms

1.3 Black Start Capability shall mean a generating unit that is capable of starting without an outside electrical supply.

1.4 Black Start Plan shall mean a plan utilizing Black Start Capability designed and implemented by the Transmission Owner in conjunction with its interconnected generation and distribution customers, Distribution System Control, other electric

systems, its Security Coordinator and ECAR, to energize portions of the Transmission System which are de-energized as a result of a widespread system disturbance.

1.5 Commission shall mean the Michigan Public Service Commission (MPSC), or its successor.

1.6 Confidential Information shall have the meaning set forth in Section 20.1 hereof.

1.7 Control Area shall mean an electric system, bounded by interconnection metering and telemetry. Generation within the Control Area is directed to operate in a manner prescribed by guidelines established by ECAR and NERC and in accordance with Good Utility Practice to (a) maintain scheduled interchange with other Control Areas, (b) maintain the operating frequency and (c) provide sufficient generating capacity to maintain operating reserves.

1.8 Distribution System shall mean, subject to and consistent with the provisions of Section 3.2 and 3.4 hereof, the equipment and facilities and the Interconnection Equipment owned, or that should be owned by the terms of this Agreement, by the Local Distribution Company and used to deliver power and energy to end users, including transformers, switches, and feeders rated at a Nominal Voltage of 138 kilovolts (kV) or less.

1.9 Distribution System Control shall mean the entity that has the ability and the obligation to operate the Distribution System Control Area to ensure that the aggregate electrical demand and energy requirements of the load is met at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements.

1.10 Distribution System Control Area shall mean a Control Area whose load and generation, and other bulk power supply points are integrated by the Transmission System.

1.11 Distribution System Control Center shall mean the electric Distribution System Control Center(s) that is/are responsible for monitoring and controlling the Distribution System in real time.

1.12 Distribution Transformer shall mean an electrical transformer which, generally, has its secondary low-side windings rated at Nominal Voltage of less than 138 kV.

1.13 Due Diligence shall mean the exercise of good faith efforts to perform a required act on a timely basis and in accordance with Good Utility Practice using the necessary technical and personnel resources.

1.14 ECAR is an acronym, which stands for the East Central Area Reliability coordination agreement. This is the Agreement under which Transmission Providers, who are signatories of the agreement, establish regional coordination

practices and guides to govern the electric coordinated operation and reliability of the East Central Region of North America. As used in this Agreement, the term ECAR includes any successor organization's reliability requirements.

1.15 Effective Date shall mean the closing date as defined in the Membership Interests Purchase Agreement between the Parties.

1.16 Eligible Customer shall have the same meaning as that term is defined under the Transmission Owner's OATT on file with the FERC.

1.17 Emergency means a condition or situation that in the reasonable good faith determination of the affected Party in accordance with Good Utility Practice contributes to an existing or imminent physical threat of danger to life or a significant threat to health, property or the environment.

1.18 Extended Outage shall mean an Unplanned Outage, in which facilities are automatically removed from service (typically by relay-action operating circuit breakers), with a duration of more than two (2) minutes.

1.19 FERC shall mean the Federal Energy Regulatory Commission or its successor federal agency.

1.20 Force Majeure shall have the meaning set forth under Article 16 hereof.

1.21 Forced Outage shall mean an Unplanned Outage, in which facilities are removed from service by operator intervention and not automatically such as by relay-action operating circuit breakers.

1.22 Good Utility Practice shall mean any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather includes all acceptable practices, methods, or acts generally accepted in the region.

1.23 Governmental Authority shall mean any foreign, federal, state, local or other governmental regulatory or administrative agency, court, commission, department, board, or other governmental subdivision, legislature, rulemaking board, tribunal, arbitrating body, or other governmental authority; provided such entity possesses valid jurisdictional authority to regulate the Parties and the terms and conditions of this Agreement.

1.24 ISO means Independent System Operator.

1.25 Interconnection Equipment shall mean all the equipment that is necessary for the interconnection of the Distribution System to the Transmission System which is located at the substations listed in Exhibit 1 hereto as it may be revised from time to time.

1.26 Interconnection Point(s) shall mean the point(s) at which the Distribution System is connected to the Transmission System, as set forth in Exhibit 1 hereto as it may be revised from time to time.

1.27 Interconnection Service shall mean the services provided by the Transmission Owner for the interconnection of the Distribution System with the Transmission System. Interconnection Service does not include the right to transmission service on the Transmission System, which service shall be obtained in accordance with the provisions of the Transmission Owner's OATT.

1.28 Interconnection Standards shall be those standards provided by the Transmission Owner to the Local Distribution Company to establish and maintain interconnection operation in compliance with standards of NERC, ECAR, applicable state or federal regulations or by mutual agreement of the Parties.

1.29 Interest Rate shall mean an annual percentage rate of interest equal to the lesser of (a) the prime rate published by the Wall Street Journal (which represents the base rate on corporate loans posted by at least 75% of the nation's banks) on the date due, plus 2%, or (b) the highest rate permitted by law.

1.30 Jointly Owned Assets shall mean those assets in which the Transmission Owner and Local Distribution Company have undivided ownership interests. Due to the nature of substation designs, many of the supporting substation assets (e.g., station batteries, fence, control houses, ground grid, yard stone, steel structures, and some protective relay equipment) cannot be separated by ownership and the Parties share in the ownership of such assets. The respective ownership of such assets by substation is shown in Exhibit 6.

1.31 Knowledge shall mean actual knowledge of the corporate officers or managers of the specified Person charged with responsibility for the particular function as of the Effective Date of this Agreement, or, with respect to any certificate delivered pursuant to the Agreement, the date of delivery of the certificate.

1.32 Least-Cost shall mean the lowest Transmission System and Distribution System facility costs, over the life of the facility, to accommodate an improvement need while adequately providing for reliability, operating, and maintenance requirements.

1.33 Reserved

1.34 Reserved

1.35 Local Distribution Company shall mean Consumers Energy Company and its successors and assigns.

1.36 Local Distribution Company Provided Services shall mean those services provided by the Local Distribution Company for the Transmission Owner by mutual agreement or contract.

1.37 Local Distribution Company's Representative shall be that person(s) identified as the point of contact for day-to-day operations of the Distribution System, identified in Section 2.3.

1.38 Momentary Outage shall mean a Distribution or Transmission System (in whole or in part) interruption in service with a duration of two (2) minutes or less.

1.39 Momentary Outage Event shall mean one or more Momentary Outages within any 60-minute period that are attributable to the same root cause.

1.40 NERC shall mean the North American Electric Reliability Council or its successor.

1.41 Network Security shall mean the ability of the Transmission System to withstand sudden disturbances such as unforeseen conditions, electric short circuits or unanticipated loss of system elements consistent with reliability principles used to design, plan, operate, and assess the actual or projected reliability of an electric system that are established by any Governmental Authority, NERC or ECAR and which are implemented by Transmission Owner or required of Transmission Owner in compliance with Security Coordinator directives.

1.42 Network Security Condition shall mean a condition or situation in which, in the reasonable good faith determination of Transmission Owner, Network Security is not satisfied or is threatened.

1.43 Nominal Voltage shall mean an accepted standard voltage level offered by the Transmission Owner, at various points on the Transmission System, including but not limited to 120 kV, 138 kV and 345 kV.

1.44 Normal System Condition shall mean any operating conditions of the Transmission System other than an Emergency or Network Security Condition.

1.45 Open Access Transmission Tariff or OATT shall mean the Open Access Transmission Tariff of the Transmission Owner on file with the FERC.

1.46 Operating Committee means the committee established pursuant to Section 6.4.3 of the Operating Agreement dated April 1, 2001, as amended and restated, between Local Distribution Company and Transmission Owner.

1.47 Party or Parties shall have the meaning set forth in the introductory paragraph of this Agreement.

1.48 Person shall mean any individual, partnership, limited liability company, joint venture, corporation, trust, unincorporated organization, or governmental entity or any department or agency thereof.

1.49 Planned Outage shall mean action by (i) Local Distribution Company or Transmission Owner to take its equipment, facilities or systems out of service, partially or completely, to perform work on specific components that is scheduled in advance and has a predetermined start date and duration pursuant to the procedures set forth in Sections 3.10.1, 3.10.2, and 3.10.4. Planned Outage shall not include the construction of new facilities or system elements, the modification of existing facilities or system elements addressed in Article 9, which includes, but is not limited to, activities associated with the construction of third party facilities or with the modifications required to accommodate third party facilities.

1.50 Planning Committee means the committee established pursuant to Section 6.4.3 of the Operating Agreement dated April 1, 2001, as amended and restated, between Local Distribution Company and Transmission Owner.

1.51 Protective Relay is a device which detects abnormal power system conditions and, in response, initiates automatic control action

1.52 Protective Relay System is a group of Protective Relays and associated sensing devices and communications equipment that detects system abnormalities and performs automatic control action to mitigate or reduce adverse effects of such abnormalities.

1.53 Qualified Personnel shall mean individuals trained for their positions in accordance with Good Utility Practice.

1.54 Radial Asset shall mean facilities used for the distribution of electric energy through a single circuit (which may consist of any number of wires or cables) running to a substation or substations to serve Local Distribution Company's load customers.

1.55 RTO means Regional Transmission Organization.

1.56 Regulated Substance means any contaminant, hazardous waste, hazardous substance, hazardous constituent, or toxic substance, as defined in the Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA), 42 USC 9601 et seq, Resource Conservation and Recovery Act (RCRA), 42 USC 6901 et seq, Toxic Substances Control Act (TSCA), 15 USC 2601 et seq, The Michigan Natural Resources and Environmental Protection Act (MCLA 324.101 et seq); or any other similar statutes now or hereafter in effect.

1.57 Release shall mean, spill, leak, discharge, dispose of, pump, pour, emit, empty, inject, leach, dump, or allow to escape into or through the environment.

1.58 Revenue Quality Metering System shall mean a system which includes current and voltage instrument transformers, secondary wiring, test switches, meter transducer(s), meter and loss compensation as set forth in Article 5.

1.59 RTU – Remote Terminal Units shall mean a device connected by a communication system to one or more master computers with appropriate software placed at various locations to collect data and perform remote control. It may also perform intelligent autonomous control of electrical systems and report the results back to the master computer(s).

1.60 Security Coordinator shall mean a NERC-approved entity that provides the security assessment and emergency operations coordination for one or more Control Areas or transmission owners and which has operational authority under NERC standards over the Transmission Owner.

1.61 Steady-State Voltage shall mean the value of a voltage after all transients have decayed to a negligible value. The root-mean-square value in the steady-state does not vary with time.

1.62 Supervisory Control and Data Acquisition (SCADA) shall mean a system that provides data acquisition, supervisory control and alarm display and control from remote field locations to control centers.

1.63 System Modification Impact shall mean a physical change to an electrical system, element or facility subject to this Agreement that would require the reclassification of the same from a Distribution System equipment, element or facility to a Transmission System equipment, element or facility, or vice versa, consistent with the facility ownership classifications provided for in Section 3.2 hereof, Good Utility Practice and applicable NERC standards.

1.64 Transmission Owner shall mean the Michigan Electric Transmission Company, LLC and its successors and assigns.

1.65 Transmission Owner's Representative(s) shall be that person(s) identified as the point for contact for day-to-day operations of the Transmission System, identified in Section 2.3.

1.66 Transmission System shall mean, subject to and consistent with the provisions of Section 3.2 and Section 3.4 hereof, any equipment and facilities for the delivery of energy across a network that are not part of the Distribution System and the equipment and facilities owned, or that should be owned by the terms of this Agreement, by the Transmission Owner for the delivery of energy across a network.

1.67 Transmission System Operations Center(s) shall mean the electric Transmission System control center(s) that is/are responsible for monitoring and controlling the Transmission System in real time.

1.68 Unplanned Outage shall mean action by Local Distribution Company or Transmission Owner to take its equipment, facilities or systems out of service, partially or completely, due to an unanticipated failure, when such removal from service was not scheduled in accordance with Sections 3.10.1, 3.10.2, and 3.10.4. Such removal from service may be automatic such as by relay-action operating circuit breakers or by operator intervention. Momentary interruptions are excluded from the definition of Unplanned Outages. Unplanned Outages include Forced Outages as well as Extended Outages.

ARTICLE 2. Operational Requirements

2.1 Subject to the terms and conditions of this Agreement, Transmission Owner shall provide Local Distribution Company Interconnection Service for each Interconnection Point identified in Exhibit 1, from the Effective Date for the term of this Agreement.

2.2 The Interconnection Points between the Transmission System and Distribution System are listed in Exhibit 1. It shall be the Transmission Owner's responsibility to annually prepare an addendum to this exhibit that shows all new or modified interconnections. The original Exhibit 1 and all addendums shall be retained for future reference.

2.3 Local Distribution Company's Representatives and Transmission Owner's Representatives are listed in Exhibit 2, as may be modified from time to time by either Party, giving written notice of changes regarding its Representative(s) to the other Party.

2.4 Interconnection Standards

2.4.1 The Interconnection Point(s) shall be established and maintained in accordance with Good Utility Practice and the applicable NERC, Federal, State, OATT and ECAR standards and policies for Transmission Owner service to Local Distribution Company.

2.4.2 Reactive Power. Transmission Owner and Local Distribution Company recognize and agree that they have a mutual responsibility for maintaining voltage at the Interconnection Points. Transmission Owner is responsible for maintaining Transmission System voltage as listed in Sections 8.1 and 8.2 and reasonably compensating for reactive power losses resulting from transmission service. The Local Distribution Company is responsible for controlling Distribution System voltage and compensating for Distribution System reactive power losses and reactive power consumed by retail customers. The Local Distribution Company may use a combination of static and dynamic reactive resources at various locations around the Transmission Owner's system. The Local Distribution Company's and the Transmission Owner's SCADA systems shall be used to determine the net exchange of reactive power on a total

interconnections basis. For those distribution substations where there are no SCADA facilities in place the reactive flows shall be determined from SCADA data on the connecting lines in conjunction with computer load flow simulations. At load levels below 90% of peak the system should be designed such that the average power factor for the sum of all Interconnection Points is between 90% lagging and 90% leading ("peak" as used here shall refer to a current year's maximum MW load for the Local Distribution Company). For load levels above 90% of peak the power factor should be at 98% (lagging or leading), or better. If the power factor falls below this minimum the Planning Committee shall review available options and determine the best method of addressing any resulting system problems.

2.5 (a) The Local Distribution Company shall comply with Transmission Owner's reasonable operating requirements or switching procedures. The Local Distribution Company shall verbally notify the Transmission Owner if the Local Distribution Company is unable to comply with this Section at any time during the term of the Agreement.

(b) The Transmission Owner shall comply with Local Distribution Company's reasonable operating requirements or switching procedures. The Transmission Owner shall verbally notify the Local Distribution Company if the Transmission Owner is unable to comply with this Section at any time during the term of the Agreement.

2.6 Local Distribution Company shall comply with the requests, orders, directives and requirements of Transmission Owner in its role of implementing the directives of the Security Coordinator. Any such requests, orders, directives or requirements of Transmission Owner must be (a) issued in accordance with Good Utility Practice, (b) not unduly discriminatory, (c) otherwise in accordance with applicable tariffs or applicable federal, state or local laws, (d) in conformance with NERC operating procedures, and (e) reasonably necessary to maintain the integrity of the Transmission System.

2.7 Load Shedding

2.7.1 Local Distribution Company shall comply, as part of a Control Area program, with installation of automatic underfrequency load shedding equipment and maintain compliance with the standards set forth in NERC and ECAR operating standards and policies at Transmission Owner's expense.

2.7.2 The Transmission Owner may direct the Local Distribution Company to shed load to maintain the reliability and integrity of the Transmission System, in accordance with the OATT. The Transmission Owner and the Local Distribution Company will comply with MPSC directives and will

endeavor to minimize the impact on the Local Distribution Company customers.

2.8 Not a Reservation for Transmission Service

2.8.1 Local Distribution Company, or an Eligible Customer under the OATT, shall be responsible for making arrangements under the OATT for transmission and any ancillary services associated with the delivery of capacity and/or energy purchased or produced by the Local Distribution Company, which services shall not be provided under this Agreement.

2.8.2 Local Distribution Company and Transmission Owner make no guarantees to the other under this Agreement with respect to transmission service that is available under the Transmission Owner's OATT or any other tariff under which transmission service may be available in the region. Nothing in this Agreement shall constitute an express or implied representation or warranty with respect to the current or future availability of transmission service. Should the Parties enter into an arrangement under the OATT or another tariff, any terms in this Interconnection Agreement that may be in conflict with that tariff shall be subordinate to the terms of that tariff.

ARTICLE 3. Ownership, Conveyance, Operation and Maintenance

3.1 The Operating Committee shall develop specific methods and procedures with respect to Local Distribution Company's and Transmission Owner's systems covering at least, but not limited to, the following areas: safety, voltage control, outage planning and implementation, service restoration, emergency operations procedures, frequency controls, environmental matters, and maintenance planning and execution.

3.2 Facility Classification and Rights

3.2.1 Facility Classifications

3.2.1.1 As between the Parties, Local Distribution Company shall be the exclusive owner, operator and constructor of Distribution System equipment, elements, and facilities, and shall have the exclusive right to build, own, operate, and maintain: (i) all equipment, elements, and facilities operated below a Nominal Voltage of 120 kV; and (ii) all new Radial Assets operated at a Nominal Voltage at or above 120 kV.

3.2.1.2 As between the Parties, Transmission Owner is and shall be the exclusive owner, operator, and constructor of Transmission System equipment, elements and facilities.

3.2.1.3 As contemplated in Section 3.4.2, a System Modification Impact will require the reclassification of a facility. Either Party may identify a physical change to the electrical functioning of any equipment, element or facility subject to this Agreement that would require the reclassification of the same from a Distribution System equipment, element or facility to a Transmission System equipment, element or facility, or vice versa, consistent with the facility ownership classifications provided for in this Section 3.2, Good Utility Practice, and applicable NERC standards. Such identification shall be made via written notice to the other Party. The conveyance of the identified equipment, element or facility shall be accomplished under the procedures identified in Section 3.4. If the other Party disputes the applicability of reclassification of a particular equipment, element or facility, then the dispute resolution procedures in Article 25 shall apply.

3.2.2 Recordkeeping

3.2.2.1 Exhibit 5 has been omitted from this Agreement. Previously, this Exhibit reflected ownership changes and the Parties agree this Exhibit is unnecessary.

3.2.2.2 Wiring Diagrams (WDs) will be updated continuously in each Party's Drawing Management System (DMS) which is shared between the Parties and approved by both Parties at least annually when Exhibit 6 is updated to show changes in ownership. For purpose of this Section 3.12, such submission and approval of changes shall be in writing consistent with Section 11.1.

3.3 All operation and maintenance activities will be the financial responsibility of the owning Party. All operation and maintenance activities on Jointly Owned Assets will be under the direction and control of the Party that owns the greater percentage of the major equipment at that location. In the case where both Parties own an equal share the Local Distribution Company shall have such direction and control. The Parties' respective share of responsibility for the costs of all operation and maintenance activities on Jointly Owned Assets shall be the same percentage as the percentage of major equipment owned by the Party in that substation as set forth in Exhibit 6 and its subsequent addendums, provided that the minority owner's ownership interest exceeds 1%; if it does not, then the majority owner will be solely responsible for these operation and maintenance costs and corresponding capital replacements. All generation-related assets owned by the Local Distribution Company in a substation will be included as a part of the Local Distribution Company's assets in making this calculation. Responsibilities related to third-party owned generation-related assets will be split according to the nominal operating voltage at the point of connection of the generation circuit. At 120 kV and above the third-party generation-related assets

will be included as a part of the Transmission Owner's assets for purposes of making this calculation. Below 120 kV the third-party generation-related assets will be included as a part of the Local Distribution Company's assets for purposes of making this calculation. Major equipment shall be defined as main power transformers, 23 kV, 46 kV, 138 kV, and 345 kV circuit breakers, power system regulators and reclosers, and 46 kV and 138 kV capacitor banks. (Any three-phase installation of such equipment shall count as a single unit). Exhibit 6 will be updated with an addendum at least annually by the Transmission Owner and approved in writing by the Local Distribution Company to show all changes in equipment ownership in the joint substations. The original Exhibit 6 and all addendums will be retained for future reference. In those substations where each Party owns assets each Party shall be financially responsible for its appropriate share of station power energy usage.

3.4 Reclassification and Conveyance

3.4.1 The facility classifications provided for in Subsection 3.2.1 hereof shall govern the Parties' ownership of existing and future Distribution System facilities and Transmission System facilities, except as provided in Subsection 3.4.2.

3.4.2 Any System Modification Impact shall require a Party to convey ownership to the appropriate Party in accordance with the ownership classifications provided for in Section 3.2 and the terms of this Section 3.4. However, no such reclassification shall affect how the other Sections of this Agreement are applied until there is a change in ownership of the facilities involved and until any related changes are made to this Agreement and its exhibits, as may be required. Upon such a change in ownership, the Planning Committee shall revise any Exhibits hereto when needed to reflect the change in ownership.

3.4.3 A facility conveyed pursuant to Section 3.4.2 shall be priced at 1.18 times the seller's net plant value but in any case, shall not be less than zero dollars (i.e., no payment from seller to purchaser will occur as a result of net plant value being less than zero). As used herein, "net plant value" shall mean the asset's original cost depreciated according to the seller's accepted accounting method. In addition, should either Party plan to abandon or otherwise take out of service any facilities which could be of use as part of the other Party's system, it shall offer to convey to the other Party such facilities before they are taken out of service under the same pricing formula outlined above.

3.4.4 All types of conveyances discussed in this Section 3.4 shall be subject to the following conditions:

(a) The Planning Committee shall within 12 months of the Effective Date of this Agreement develop appropriate timeframes and procedures for

accomplishing such conveyances. For the avoidance of doubt, any previous agreements, understandings, or practices between the Parties on this subject matter that in any way conflict with the terms of this Agreement, including but not limited to anything stated in Planning Practice 6, are hereby abrogated and superseded by this Agreement.

(b) At least 12 months (or as close as feasible to 12 months) before implementing system modifications which would result in such a conveyance, the Party planning to do such modifications shall notify the other Party of such plans. The other Party, if it wishes, shall then have 2 months within which to propose an alternative modification which is consistent with Good Utility Practice, which would reduce or eliminate the need for conveyances, and which would cost the Party seeking to do the modifications no more than the originally proposed modification. If such an alternative is provided in a timely manner, the Party proposing to do the modification shall consider the alternative and shall not unreasonably refuse to pursue the alternative instead of the original proposal.

(c) Possible impediments to timely conveying the property in question (e.g., difficulty in getting release from the conveyor's indenture) shall be referred to the Administrative Committee. The Administrative Committee is authorized to modify the requirements of this Section with regard to such a specific proposed modification however it deems appropriate in light of the possible impediment and other circumstances.

3.5 Each Party shall operate any equipment that might reasonably be expected to have impact on the operations of the other Party in a safe and efficient manner and in accordance with all applicable federal, state, and local laws, NERC operating practices, and Good Utility Practice, and otherwise in accordance with the terms of this Agreement. Each Party shall comply with the reasonable requests, orders, directives and requirements of the other Party, which are authorized under this Agreement.

3.6 (a) Without limiting the generality of Section 3.5, Local Distribution Company shall own, operate, and maintain its Distribution System in a manner in accordance with Good Utility Practice to prevent degradation of voltage or services of the Transmission System. The Local Distribution Company shall be responsible for the costs to repair or replace the Distribution System and Local Distribution Company's Interconnection Equipment.

(b) Without limiting the generality of Section 3.5, Transmission Owner shall own, operate, and maintain its Transmission System in a manner in accordance with Good Utility Practice to prevent degradation of voltage or services of Local Distribution Company's Distribution System. The Transmission Owner shall be responsible for the costs to repair or replace the Transmission System and Transmission Owner's Interconnection Equipment.

(c) Without limiting the generality of Section 3.5, Local Distribution Company or Transmission Owner, as appropriate pursuant to Section 3.3 hereof, shall operate and maintain Jointly Owned Assets in a manner in accordance with Good Utility Practice to prevent degradation of voltage or services to either Party.

3.7 (a) Except during an Emergency, Local Distribution Company shall not, without prior Transmission Owner authorization, operate any Transmission Owner circuit, including transformer, line, or bus elements. Local Distribution Company shall retain the right to operate Transmission Owner equipment during an Emergency. When practical, prior to operation of such equipment, Local Distribution Company shall provide notice to the Transmission Owner. The Local Distribution Company shall also have the right to operate Transmission Owner substations that serve five or fewer customers to maintain the integrity of the Distribution System under the specific real time direction of the Transmission Owner. The Local Distribution Company shall not operate any Transmission System circuit if upon notice the Transmission Owner expressly refuses to grant permission to the Local Distribution Company. Within five (5) working days of such Emergency, Local Distribution Company shall provide written explanation of such Emergency to Transmission Owner.

(b) Except during an Emergency, Transmission Owner shall not, without prior Local Distribution Company authorization, operate any Local Distribution Company circuit, including transformer, line, or bus elements. Transmission Owner shall retain the right to operate Local Distribution Company equipment, during an Emergency for imminent personnel safety threat, to prevent damage to equipment or to maintain the integrity of the Transmission System. When practical, prior to operation of such equipment, Transmission Owner shall provide notice to Local Distribution Company. Transmission Owner shall not operate any Distribution System circuit if upon notice the Local Distribution Company expressly refuses to grant permission to the Transmission Owner. Within five (5) working days of such Emergency, Transmission Owner shall provide written explanation of such Emergency to Local Distribution Company.

(c) In an Emergency, joint facilities shall be operated by the Party able to first respond with Qualified Personnel.

3.8 Local Distribution Company and Transmission Owner shall design, install, test, calibrate, set, and maintain their respective Protective Relay equipment in accordance with Good Utility Practice, applicable federal, state, or local laws and this Agreement, as set forth in Article 6 hereof. In the case of jointly owned relaying equipment, the Party having direction and control pursuant to Section 3.3 hereof shall design, install, calibrate, set, and maintain Protective Relay equipment in accordance with Good Utility Practice. Without limiting the generality of Section 3.6(c) above, costs for such work will be split between the

Companies on a predetermined ownership percentage basis as set forth in the then-current version of Exhibit 6, provided that the minority owner's ownership interest exceeds 1%; if it does not, then the majority owner will be solely responsible for these costs.

3.9 (a) If Transmission Owner reasonably determines that (i) any of Local Distribution Company's Interconnection Equipment fails to perform in a manner in accordance with Good Utility Practice or this Agreement, or (ii) Local Distribution Company has failed to perform proper testing or maintenance of its Interconnection Equipment in accordance with Good Utility Practice or this Agreement, Transmission Owner shall give Local Distribution Company written notice to take corrective action. Such written notice shall be provided by Transmission Owner to Local Distribution Company's Representative as soon as practicable upon such determination. If Local Distribution Company fails to initiate corrective action promptly, and in no event later than seven (7) days after the delivery of such notification, and if in Transmission Owner's reasonable judgment leaving Local Distribution Company's Distribution System connected with Transmission System would create an Emergency or Network Security Condition, Transmission Owner may, with as much prior verbal notification to Local Distribution Company and Distribution System Control as practicable, open only the Interconnection Point(s) needing corrective action connecting the Local Distribution Company and Transmission Owner until appropriate corrective actions have been completed by Local Distribution Company, as verified by Transmission Owner. Prior to taking such action, Transmission Owner shall give appropriate consideration to the needs of the Local Distribution Company's end-use customers. Transmission Owner's judgment with regard to an interruption of service under this paragraph shall be made in accordance with Good Utility Practice and subject to Section 3.1 hereto. In the case of such interruption, Transmission Owner shall immediately confer with Local Distribution Company regarding the conditions causing such interruption and its recommendation concerning timely correction thereof. Both Parties shall act promptly to correct the condition leading to such interruption and to restore the connection.

(b) If Local Distribution Company reasonably determines that (i) any of Transmission Owner's Interconnection Equipment fails to perform in a manner in accordance with Good Utility Practice or this Agreement, or (ii) Transmission Owner has failed to perform proper testing or maintenance of its Interconnection Equipment in accordance with Good Utility Practice or this Agreement, Local Distribution Company shall give Transmission Owner written notice to take corrective action. Such written notice shall be provided by Local Distribution Company to Transmission Owner's Representative as soon as practicable upon such determination. If Transmission Owner fails to initiate corrective action promptly, and in no event later than seven (7) days after the delivery of such notification, and if in Local Distribution Company's reasonable judgment leaving Transmission System connected with Local

Distribution Company's Distribution System would create an Emergency, Local Distribution Company may, with as much prior verbal notification to Transmission Owner and Distribution System Control as practicable, open only the Interconnection Point(s) needing corrective action connecting the Transmission Owner and Local Distribution Company until appropriate corrective actions have been completed by Transmission Owner, as verified by Local Distribution Company. Local Distribution Company's judgment with regard to an interruption of service under this paragraph shall be made in accordance with Good Utility Practice and subject to Section 3.1 hereto. In the case of such interruption, Local Distribution Company shall immediately confer with Transmission Owner regarding the conditions causing such interruption and its recommendation concerning timely correction thereof. Both Parties shall act promptly to correct the condition leading to such interruption and to restore the connection.

3.10 Outages

3.10.1 Outage Authority and Coordination. In accordance with Good Utility Practice, each Party may, in close cooperation with the other, remove from service its system elements that may impact the other Party's system as necessary to perform maintenance or testing or to replace installed equipment. Absent the existence of an Emergency, the Party scheduling a removal of a system element from service will schedule such removal on a date mutually acceptable to both Parties, in accordance with Good Utility Practice.

3.10.2 The Parties shall coordinate inspections, Planned Outages, and maintenance of their respective equipment, facilities and systems so as to minimize the impact on the availability, reliability and security of both Parties' systems and operations when the outage is likely to have a materially adverse impact on the other Party's system or the Local Distribution Company's end-use customers. Subject to the confidentiality provisions of Article 20, on or before October 1 of each year during the term hereof, the Parties shall exchange non-binding Planned Outage schedules for the following calendar year, which shall be developed and followed in accordance with Good Utility Practice, for the Distribution System and Transmission System. The Parties shall communicate the outage schedules as promptly as possible, provided that in no event shall such schedule be provided less than fifteen (15) days prior to a Planned Outage. The Parties shall keep each other updated regarding any changes to such schedules.

3.10.3 Unplanned Outages

3.10.3.1 Distribution System Unplanned Outage. In the event of an Unplanned Outage of a system element of the Distribution System adversely affecting the Transmission System, the Local

Distribution Company will act in accordance with Good Utility Practice to promptly restore that system element to service unless the Local Distribution Company obtains concurrence from the Transmission Owner that some deferral is reasonable, and this concurrence shall not be unreasonably withheld. The Local Distribution Company shall plan and maintain its Distribution System such that the average length of distribution system outages having a direct impact on the Transmission System shall not exceed 166 minutes per event on an annual basis. For any year in which the average outage duration exceeds this limit, the Local Distribution Company shall develop a plan to improve the outage restoration process and reduce outages and shall obtain the Transmission Owner's concurrence with this plan. Within forty-eight hours (48) of the beginning of any Unplanned Outage, the Local Distribution Company shall provide the Transmission Owner with a restoration plan.

3.10.3.2 Transmission System Unplanned Outage. In the event of an Unplanned Outage of a system element of the Transmission System adversely affecting the Local Distribution Company's Distribution System, the Transmission Owner will restore the system to normal as soon as possible unless the Transmission Owner obtains concurrence from the Local Distribution Owner that some deferral is reasonable, and this concurrence shall not be unreasonably withheld. The Transmission Owner shall plan and maintain its Transmission System such that the average length of Transmission System outages having a direct impact on customers of the Local Distribution Company shall not exceed 166 minutes on an annual basis. For any year in which the average outage duration exceeds this limit, the Transmission Owner shall develop a plan to improve the outage restoration process and reduce outages and shall obtain the Local Distribution Company's concurrence with this plan. Within forty-eight hours (48) of the beginning of any Unplanned Outage the Transmission Owner shall provide the Local Distribution Company with a restoration plan. For any 138 kV system outage it is expected that the system will be restored to its normal configuration within seven (7) days; for any 345 kV system outage it is expected that the system will be restored to its normal configuration within thirty (30) days. If it is expected that any Unplanned Outage will exceed these limits the Transmission Owner shall provide the Local Distribution Company with detailed information on measures being taken to minimize the outage time.

3.10.4 Planned Outages

3.10.4.1 Distribution System Planned Outage. In the event of a Planned Outage of a system element of the Distribution System adversely affecting the Transmission System, the Local Distribution Company will act in accordance with Good Utility Practice to promptly restore that system element to service in accordance with its schedule for the work that necessitated the Planned Outage.

3.10.4.2 Transmission System Planned Outage. The Transmission Owner shall review all Transmission System Planned Outages with the Local Distribution Company. In the event of a Planned Outage of a system element of the Transmission System adversely affecting the Local Distribution Company's Distribution System, the Transmission Owner will act in accordance with Good Utility Practice to promptly restore that system element to service in accordance with its schedule for the work that necessitated the Planned Outage.

3.11 The Parties shall use best efforts in accordance with Good Utility Practice to coordinate operations in the event of any Forced or Planned Outage that affects the other Party's system.

3.12 Black Start Plan Participation. In accordance with Good Utility Practice, Local Distribution Company agrees to participate in Transmission Owner's Black Start Plan for the Distribution System and the Transmission System, as well as any verification testing.

3.13 The Parties shall notify and make available in a timely manner, electric system modeling information necessary for the other Party to monitor, analyze, and protect its facilities in a real time environment, no less than 30 days prior to the energization of new or reconfigured network facilities.

ARTICLE 4. Supervisory Control and Data Acquisition, SCADA

4.1 If the Transmission Owner chooses to operate its own SCADA system, or to make modifications or additions to the existing system, the following terms and conditions of this Article 4 will apply.

4.2 Interconnection Points containing SCADA and communications equipment installed prior to April 1, 2001, shall be considered to satisfy the terms and conditions of this article. For those Interconnection Points that existed prior to April 1, 2001 that did not contain SCADA and communications equipment, and for new Interconnection Points installed after April 1, 2001 where SCADA and communications equipment is necessary for and requested by the Transmission Owner to perform monitoring, state estimation and contingency analysis, the Local Distribution Company shall install and operate such equipment at the

Transmission Owner's expense. Each Interconnection Point or other mutually agreeable location with SCADA and communications equipment shall have one dedicated communications path to the Local Distribution Company's control center for the RTU data. The cost of the dedicated communications path and general use station phone shall be shared on an equal basis. Additional data paths, SCADA equipment, and communications equipment requested, either emanating from the substation, the Local Distribution Company's control center, or the Transmission Owner's control center, will be at the expense of the requestor. This data and status information may be real time or with a time delay mutually acceptable to the Parties. The method of providing this data and control will be via an industry standard protocol such as Inter-Control Center Protocol (ICCP) or other method agreed to by the Parties. Such data may include, but not be limited to megawatts, megavars, voltage, amperes, device status, interchange schedule error, and communication system status.

4.3 The Transmission Owner reserves the right at its expense, to require, for new, or modified Local Distribution Company Interconnection Points, installation of a Transmission Owner's RTU or installation of a dual port RTU to provide data and control directly to the Transmission Owner within the Local Distribution Company's substation. The Local Distribution Company will assist in furnishing desired inputs for the Transmission Owner's RTU.

4.4 The operating metering system shall consist of instantaneous values of MW, MVAR, and voltage.

4.4.1 Values shall be inputted to a RTU or comparable communication device for communication with the Party having Control Area responsibility.

4.4.2 Transducers may utilize the voltage transformers and current transformer secondary circuits also utilized by the revenue metering equipment for a particular interconnection. In such case, the performance criteria listed in Exhibit 4 of the Agreement, Metering Specifications, for the voltage transformers and the current transformers, shall apply. Relaying class voltage transformers and or current transformers shall not be utilized unless mutually agreed between all the owners of the metering equipment and the Local Distribution Company.

4.4.3 Transducers shall have maximum 0.3% inaccuracy. Transducers shall be field calibrated as necessary but at least once every ten (10) years and documentation shall be retained showing the calibration results until next calibration.

4.4.4 Telemetry shall be maintained and calibrated such that overall inaccuracy of MW, MVAR, and voltage values is less than 1.0% of full scale.

4.5 To the extent new RTUs and associated communications equipment is to be installed, the Local Distribution Company shall install or facilitate installation of

the RTU and associated communications equipment as soon as practicable, provided that installation shall be accomplished within a time period of no more than 270 days following notice by Transmission Owner or prior to commissioning of any new Interconnection Points.

ARTICLE 5. Revenue Metering

5.1 Transmission Owner shall own, operate, test and maintain any metering equipment at the Interconnection Points, as required by this Article 5 not including any metering equipment owned by the Local Distribution Company for use in metering its end-use customers. Transmission Owner and Local Distribution Company agree that, as to all Interconnection Points in existence as of the Effective Date, no new or different metering equipment or arrangements shall be required. For existing Interconnection Points where low-side metering exists without loss compensation, the Parties will agree to adjust the metering data in such a manner to account for any real power losses between the location of the meter and the Interconnection Point. To the extent existing metering equipment is replaced and when new metering equipment is installed at Interconnection Points in existence as of the Effective Date, such replacements or installations shall meet the standards set in Section 5.2. Transmission Owner shall provide, install, own, operate, test, and maintain the new metering equipment located at the Interconnection Points.

5.2 The Revenue Quality Metering System shall consist of all instrument transformers (current and voltage), secondary wiring, test switches, and meter(s) required to determine the metering values for record for any given metering point

5.2.1 Metering shall be form 9, 3-element for 4-wire systems and form 5, 2-element for 3-wire systems.

5.2.2 Meters shall measure, at a minimum, megawatt hours and megavar hours and have bi-directional capability, where applicable. All measured values shall have individual outputs where applicable and a minimum 35-day interval data recording capability for each measured value.

5.2.3 Whenever feasible, any new metering facilities shall be located at the same physical location as the Interconnection Point. If it is not reasonable to have the metering facilities and the Interconnection Point at the same physical location, the metering data will be adjusted to account for real power losses between the location of the meter and the Interconnection Point.

5.2.4 Transmission Owner shall maintain records that demonstrate compliance with all meter tests and maintenance conducted in accordance with Good Utility Practice for the life of the Interconnection Point. Local Distribution Company shall have reasonable access to the records.

5.2.5 For installations where the metering is performed using loss compensation, the factory certified test results of the power transformer, if available, including load, no-load losses and calculated meter loss calculations, shall be recorded in a written record. Local Distribution Company shall have reasonable access to the records.

5.2.6 Transmission Owner shall maintain records of the factory certified test results, or the utility test shop test results, showing compliance of the meters with the applicable metering test standards.

5.2.7 Transmission Owner's Metering equipment shall be tested by Transmission Owner at its own expense not less than once every year, unless an extension of the testing cycle is agreed upon by the Parties. The accuracy of such metering equipment shall be maintained by Transmission Owner in accordance with applicable regulatory standards. At the request of either Party, special tests shall be made. If any special meter test discloses the metering device to be registering within acceptable limits of accuracy as specified herein, then the Party requesting such special meter test shall bear the expense thereof. Otherwise, the expense of such test shall be borne by the owner. Representatives of either Party shall be afforded opportunity to be present at all routine or special tests and upon occasions when any readings for purposes of settlements hereunder are taken from meters not producing an automatic record.

5.2.8 If, as a result of any test, any meter shall be found to be registering more than two (2) percent above or below one hundred (100) percent of accuracy, the account between the Parties hereto shall be corrected for a period equal to one-half of the elapsed time since the last prior test, according to the percentage of inaccuracy so found, except that if the meter shall have become defective or inaccurate at a reasonably ascertainable time since the last prior test of such meter, the correction shall extend back to such time. No meter shall be left in service if found to be more than two (2) percent above or below one hundred (100) percent of accuracy. Should metering equipment at any time fail to register, the energy delivered shall be determined from the best available data. All meters shall be kept under seal, such seals to be broken only when the meters are to be tested or adjusted.

5.2.9 Test switches shall be installed to allow independent testing and/or replacement of each meter and transducer utilizing the secondary circuit so as not to interrupt the operation of other devices utilizing the secondary circuit.

5.2.10 In substations where an RTU or other remote data collecting and telecommunication device is present, meters shall have form C, 3-wire

outputs with programmable values determined by the Transmission Owner for bi-directional MWHs and MVARs.

5.2.11 In the event an interconnection meter needs replacement or repair, a representative from Local Distribution Company shall be given a reasonable opportunity to be present during such repair or replacement.

ARTICLE 6. Protective Relaying and Control

6.1 Transmission Owner and the Local Distribution Company shall, in accordance with Good Utility Practice, coordinate, review and approve all new Protective Relaying equipment, including equipment settings, Protective Relay schemes, drawings, and functionality associated with each Interconnection Point. Protective Relaying equipment and schemes installed before the date of this agreement shall be considered to satisfy the terms and conditions of this Article 6. When existing equipment or schemes are replaced or when new equipment or schemes are installed per this Article 6 or in association with new Interconnection Points, then the terms and conditions of Article 6 shall apply. Each Party shall incur the expense for the work on its system.

6.2 To the extent that there is generation on the Distribution System which, in the reasonable judgment of either Party, may contribute material amounts of current to a fault on the Transmission System, the Local Distribution Company shall have and enforce standards to ensure the provision, installation and maintenance of relays, circuit breakers, and all other devices necessary to promptly remove any fault contribution of such generation to any short circuit occurring on the Transmission System and not otherwise isolated by the Transmission Owner equipment. Such standards will be included in the Local Distribution Company's connection requirements for generation. Transmission Owner and Local Distribution Company shall not be responsible for protection of such generation.

6.3 Transmission Owner shall own, operate, maintain and test those Protective Relay Systems that control their breakers or equivalent protective devices. Local Distribution Company shall own, operate, maintain, and test those Protective Relay Systems that control their breakers or equivalent protective devices governed by this Article 6. The Parties shall maintain, and, as necessary, upgrade their respective Protective Relay Systems and shall provide the other Party with access to available copies of operation and maintenance manuals and test records for all relay equipment upon request. The Transmission Owner will provide protective relay settings for the relays that control breakers or equivalent protective devices owned by the Local Distribution Company that also protect Transmission Owner's equipment. The Local Distribution Company will review and apply the settings.

6.4 The owner (Transmission Owner or Local Distribution Company) of the line will provide the relay communication channel necessary for line protection at its

expense. Owner will participate with other Party to test communication schemes upon request without charge.

6.5 The Parties shall test their respective relays associated with the Interconnection Points for correct calibration and operation. Parties shall coordinate design, installation, operation, and testing of Protective Relay schemes to insure that such relays operate in a coordinated manner so as to not cause adverse operating conditions on the other Party's system.

6.6 Local Distribution Company shall be responsible for Protective Relay maintenance, calibration and functional testing of relay systems that protect Local Distribution Company's equipment associated with the Interconnection Points and that protect Transmission Owner from Local Distribution Company's Interconnection Equipment to the extent such calibration and testing are in accordance with Good Utility Practice. All such maintenance and testing must be performed by Qualified Personnel selected by the Local Distribution Company. In addition, Local Distribution Company shall allow Transmission Owner to conduct visual inspection of all Protective Relays and associated maintenance records directly related to the interconnection. Related maintenance and operational records shall be maintained by the Local Distribution Company in accordance with Good Utility Practice. Upon completion of Protective Relay calibration testing and relay functional testing, Local Distribution Company shall make available copies of test reports and related records for review by Transmission Owner upon request. Local Distribution Company shall review test reports and document that Protective Relay System's tests and settings, as shown on such test reports, have been done in accordance with the equipment's specifications and Good Utility Practice.

6.7 (a) As Transmission Owner's system protection requirements change, Transmission Owner will upgrade its Protective Relaying System in accordance with Good Utility Practice. If these upgrades affect the serviceability and acceptability of the Protective Relaying Systems on the Interconnection Equipment which may be installed, owned, and operated by Local Distribution Company, the Local Distribution Company must upgrade its Protective Relay Systems at its expense (unless such modifications are required in association with the addition of generation to the system in which case Section 9.8 shall apply) as necessary to bring them into compatibility with that installed by Transmission Owner. Transmission Owner shall give Local Distribution Company notice of such upgrade as soon as practicable prior to the anticipated date of such upgrade. Any proposed protective system upgrades shall be reviewed by the Planning Committee in accordance with Section 7.3(vi) hereof.

(b) As Local Distribution Company's system protection requirements change, Local Distribution Company will upgrade its Protective Relaying System in accordance with Good Utility Practice. If these upgrades affect the serviceability and acceptability of the Protective Relaying Systems on the Interconnection Equipment which may be installed, owned, and operated by Transmission Owner,

Transmission Owner must upgrade its Protective Relaying Systems at its expense (unless such modifications are required in association with the addition of generation to the system in which case Section 9.8 shall apply) as necessary to bring them into compatibility with that installed by Local Distribution Company. Local Distribution Company shall give Transmission Owner notice of such upgrade as soon as practicable prior to the anticipated date of such upgrade. Any proposed protective system upgrades shall be reviewed by the Planning Committee in accordance with Section 7.3(vi) hereof.

6.8 Local Distribution Company shall provide necessary space to install or expand relay panels for substation system protection if requested by Transmission Owner. Any incremental costs required to accommodate such request shall be the responsibility of the Transmission Owner.

6.9 Transmission Owner shall provide the necessary space to install or expand relay panels for substation system protection if requested by Local Distribution Company. Any incremental costs required to accommodate such request shall be the responsibility of the Local Distribution Company.

6.10 Each Party will provide fault recorder, sequence of events, and relay information to the other party as needed and in a reasonable amount of time.

ARTICLE 7. Planning and Obligation to Serve

7.1 Adequacy Obligation. Subject to applicable regulatory approvals, including adherence to Least-Cost planning requirements and principles, adherence to applicable NERC, ECAR or other regional reliability council or successor organization's reliability requirements, and all other applicable operating reliability criteria and subject to the oversight and direction of the appropriate RTO or ISO, the Transmission Owner shall operate, maintain, plan and construct its Transmission System in accordance with Good Utility Practice in order to:

(i) deliver on a reliable basis the projected capacity and energy needs of all loads served by the Local Distribution Company's Distribution System and dependent upon the Transmission Owner's facilities for delivery of such energy to the Distribution System;

(ii) provide needed support to the Local Distribution Company where a transmission addition is the Least-Cost electric solution to an improvement need, including but not limited to, the reliability needs of the Local Distribution Company; and

(iii) deliver energy from both existing and new generating facilities connected to and dependent upon Transmission Owner's transmission of such energy

7.2 With regard to planning and construction of projects which affect Local Distribution Company and Local Distribution Company's load-serving area, the

Parties shall develop methods and procedures covering at least the following areas:

(i) coordination between short-term and long-term distribution and transmission planning;

(ii) developing and sharing computer simulation models needed to support Transmission Owner and Local Distribution Company planning activities;

(iii) coordination of permitting (including local and state approvals) and siting;

(iv) engineering and scheduling of new projects;

(v) construction and inspection standards;

(vi) information-sharing and priority-setting; and

(vii) health and safety issues.

7.3 With respect to Local Distribution Company's load-serving area, the Planning Committee, shall:

(i) implement the methods and procedures developed pursuant to Section 7.2;

(ii) review planning studies and reports regarding projects needed or proposed for the area in the next five (5) years, or as determined by the Planning Committee;

(iii) recommend additional studies or evaluation of plans;

(iv) follow Least-Cost planning principles in recommending specific projects;

(v) at least once every year, prepare a planning report which shall include in priority order a list of projects proposed by either Party for the next year, the estimated costs of such projects, and the timetable for such projects, including the in-service date; and

(vi) review proposed programmatic changes to the electric system, including protective system upgrades.

7.4 If the Parties agree upon the need for any such project, they shall cooperate and coordinate in seeking all necessary regulatory approvals for such project. Transmission Owner shall coordinate and cooperate with Local Distribution

Company with respect to all communications and commitments to municipal, county, and state agencies involved in such project.

7.5 If Local Distribution Company proposes construction of a transmission project and Transmission Owner does not agree that such project is needed, Local Distribution Company shall have the right to petition an appropriate RTO, ISO or applicable regulatory agency for a declaratory ruling on whether the proposed project is needed pursuant to Transmission Owner's public-utility duty to plan and construct a reliable, adequate Transmission System.

7.6 Load Growth and Reliability Needs. Transmission Owner is obligated to plan and install any Transmission System components that may be necessary, as determined by a Least-Cost planning process in accordance with Section 7.1 and consistent with the established and consistently applied reliability criteria of the Parties, to accommodate Local Distribution Company's planned load growth and planned reliability improvements. Transmission Owner will construct new interconnections to Local Distribution Company facilities in accordance with Transmission Owner's planning criteria, other agreements in effect between the Parties, and Good Utility Practice. Transmission Owner shall bear the responsibility for such planning and installing in accordance with this Article 7. Transmission Owner's obligations under this Section 7.6 shall include the planning and installation of any new Interconnection Points that may be necessary to accommodate Local Distribution Company's planned load growth and planned reliability improvements. Recovery of the cost of such additions shall be in accordance with the OATT or other applicable tariff.

7.7 Local Distribution Company shall be the first point of contact and the wire-services provider for end-use customers.

7.8 Transmission Owner shall annually submit to Local Distribution Company, no later than February 1 of each year:

(i) Transmission Owner's plans covering the next five (5) years, or as determined by the Planning Committee, for installing Transmission System components that may be necessary to accommodate Local Distribution Company's planned load growth and reliability improvements as described in Section 7.6. Transmission Owner's plans shall include, but not be limited to, cost estimates and installation schedules for Transmission System components, and shall provide specific detail sufficient to allow Local Distribution Company to compare Transmission Owner's plans with Local Distribution Company's in-service requirements to meet its planned load growth and reliability needs.

(ii) A description of any changes to the Local Distribution Company's Distribution System that may be needed to accommodate

Transmission Owner's plans set forth in Section 7.8(i) will be requested by the Transmission Owner.

(iii) Projected voltage levels under Normal System Conditions and Transmission Owner's FERC 715 Planning criteria conditions at anticipated annual peak load and 80% of anticipated annual peak load for each Interconnection Point with planned additions for the next five (5) years, or as determined by the Planning Committee.

7.9 Local Distribution Company shall annually submit to Transmission Owner:

(a) no later than December 1 of each year, the most recent actual summer and winter demands in megawatts (MW) and megavars (MVAR) for all Interconnection Points connected to the Transmission System at the time of the Transmission Owner's most recent seasonal system peaks (Transmission Owner must provide the Local Distribution Company the day and hour of such peak no later than September 1); and

(b) no later than February 1 of each year:

(i) annual peak demand forecasts in MW for each Local Distribution Company Interconnection Point to the Transmission System for the next five (5) years, or as determined by the Planning Committee, together with corresponding projected power factors; and

(ii) planned facility (new Interconnection Points) connections to the Transmission System for the next five (5) years, or as determined by the Planning Committee.

ARTICLE 8. Transmission Service Level

8.1 Subject to applicable regulatory approvals, including adherence to Least-Cost planning requirements and principles, adherence to applicable NERC, ECAR or other regional reliability council or successor organization's reliability requirements, and all other applicable operating reliability criteria and subject to the oversight and direction of the appropriate RTO or ISO, the Transmission Owner shall operate, maintain, plan and construct its Transmission System in accordance with Good Utility Practice to provide the following service levels:

(i) A minimum Steady-State Voltage of 0.97 Per Unit (PU) at all Interconnection Points with Local Distribution Company with all influential Transmission Owner facilities in service (no contingency conditions);

(ii) A minimum Steady-State Voltage of 0.92 PU at all Interconnection Points with the Local Distribution Company influenced by one or more Transmission Owner facilities out of service (contingency conditions);

(iii) A maximum Steady-State Voltage of 1.05 PU at all Interconnection Points with the Local Distribution Company during all operating conditions;

(iv) An adequate Transmission System that shall not load Local Distribution Company facilities above normal ratings during peak load conditions with all influential Transmission Owner facilities in service (no contingency conditions);

(v) An adequate Transmission System that shall not load Local Distribution Company facilities above emergency ratings during peak load conditions with one or more influential Transmission Owner facilities out of service (contingency conditions);

(vi) On a three-year rolling average, experience no more than 0.357 Momentary Outage Events per 138 kV line protective zone (system average) and 0.743 Momentary Outage Events per 345 kV line protective zone (system average) per year. As used in this Article 8 the term “year” shall mean calendar year; and the term “line protective zone” is illustrated and defined as follows: Any given electrical fault on a transmission line will trip specific circuit breakers in a normally functioning system. All of the possible line fault locations that will trip these specific circuit breakers constitute the same line protective zone. Physically, a line protective zone consists of the conductors located between the current transformers that provide sensing to trip the circuit breakers for a line fault;

(vii) Experience no more than three (3) Momentary Outage Events on any given 138 kV line protective zone and two (2) Momentary Outage Events on any given 345 kV line protective zone per year;

(viii) On a three-year rolling average, experience no more than 0.21 Unplanned Outages per 138 kV line protective zone (system average) and 0.18 Unplanned Outages per 345 kV line protective zone (system average) per year;

(ix) Experience no more than four (4) Unplanned Outages on any given 138 kV line protective zone and three (3) Unplanned Outages on any given 345 kV line protective zone per year;

(x) Should the Transmission Owner fail to meet any of the requirements of Section 8.1(vi) or 8.1(viii) by more than 10% two years in a row, the Transmission Owner shall pay, as liquidated damages and not as a penalty, to the Local Distribution Company, an amount equal to one half of one percent (0.5%) of the annual revenue paid by the Local Distribution Company under the applicable transmission tariff; such liquidated damages amount shall be based upon the revenue received

in the second year of such failure. Such liquidated damages amount shall be increased by one half of a percent (0.5%) for each additional 10% by which the Transmission Owner fails to meet the any of the given outage targets, up to a maximum of 4.0% of the annual revenue. Outage events affecting 15% or more of transmission line protective zones within a 24-hour period will not be counted toward the requirements of Section 8.1.

If transmission service does not meet the requirements of this Article 8, Transmission Owner shall present an action plan acceptable to the Local Distribution Company within sixty (60) days of non-compliance of this Article 8 to restore transmission service to the minimum standards as described in this Article 8 in a timely manner. Should the Transmission Owner fail to correct the deficiency(s) within one year of notification from the Local Distribution Company, the Local Distribution Company shall have the right to take corrective action at the Transmission Owner's expense. The Local Distribution Company shall defer taking such actions for corrective measures normally requiring longer than one year to complete, provided the Transmission Owner is diligently pursuing such measures.

8.2 Should the Michigan Public Service Commission (MPSC) adopt service quality standards that the Local Distribution Company must meet that are more stringent than current historical performance; and should the transmission service level provided by the Transmission Owner directly or indirectly influence the Local Distribution Company's ability to meet such standards, the Local Distribution Company will promptly notify the Transmission Owner of such proposal and the Transmission Owner shall have an opportunity to participate either as a party or in cooperation with the Distribution Company, in any related MPSC hearings or proceedings. Subject to the foregoing and to any required approval by FERC, the Transmission Owner shall be responsible for meeting its proportional share of the adopted service quality standard and for any penalties that might be assessed if the standards are not met.

8.3 Transmission Owner and the Local Distribution Company acknowledge that the Special Manufacturing Contracts in existence at the time of the original execution of the 2001 Amendment and Restatement of the Distribution-Transmission Interconnection Agreement and previously listed under this Exhibit 3 are no longer in effect or no longer have clauses with compensable disruptions/interruptions associated with them. As such, the Parties have agreed to omit Exhibit 3.

ARTICLE 9. New Construction and Modification

9.1 Subject to this Article 9, Transmission Owner may construct additional Transmission System elements or modify the existing Transmission System and Local Distribution Company may construct additional Distribution System

elements or modify the existing Distribution System. All such modifications and construction provided for herein, shall be conducted in accordance with Good Utility Practice and all applicable NERC and ECAR Standards. The Party that modifies the system elements or constructs new system elements is obligated to maintain the transmission, distribution and communications capabilities of the other Party in accordance with Good Utility Practice to avoid or minimize any adverse impact on the other Party. The Parties shall look to the operating history of the Local Distribution Company in the relevant geographic area prior to the Effective Date of this Agreement, where available, in determining what constitutes Good Utility Practice.

9.2 Notwithstanding the foregoing, no modifications to or new construction of facilities or access thereto, including but not limited to rights-of-way, fences, and gates, shall be made by either Party which might reasonably be expected to have a material effect upon the other Party with respect to operations or performance under this Agreement, without providing the other Party with sufficient information regarding the work prior to commencement to enable such Party to evaluate the impact of the proposed work on its operations. The information provided must be of sufficient detail to satisfy reasonable Transmission Owner or Local Distribution Company review and operational requirements. Each Party shall use reasonable efforts to minimize any adverse impact on the other Party.

9.3 If any Party intends to install any new facilities, equipment, systems, or circuits or any modifications to existing or future facilities, equipment, systems or circuits that could reasonably be expected to have a material effect upon the operation of the other Party, the Party desiring to perform said work shall, in addition to the requirements of Section 9.2, provide the other Party with drawings, plans, specifications and other necessary documentation for review at least 60 days prior to the start of the construction of any such installation. This notice period shall not apply to modifications or new installations made to resolve or prevent pending Emergency or Network Security Conditions.

9.4 The Party reviewing any drawings, plans, specifications, or other necessary documentation for review shall promptly review the same and provide any comments to the performing Party no later than 30 days prior to the start of the construction of any installation. Unless system modifications are required in association with the addition of generation to the system (in which case Section 9.8 hereof shall apply) all such reviews shall be performed at no cost to either Party. The performing Party shall incorporate all requested modifications to the extent required in accordance with Good Utility Practice and compliance with this Agreement.

9.5 Within 180 days following placing in-service of any modification or construction subject to this Article 9, the Party initiating the work shall provide “as built” drawings, plans and related technical data to the other Party. Approval or review of any document referenced herein shall not relieve the initiating Party of its responsibility for the design or construction of any proposed facility, nor shall it

subject the other Party to any liability, except with respect to the confidentiality provisions of Article 20.

9.6 Each Party shall, at its own expense, have the right to inspect or observe all maintenance activities, equipment tests, installation work, construction work, and modification work to the facilities of the other Party that could have a material effect upon the facilities or operations of the first Party.

9.7 Construction and installation of any facility shall meet all or exceed all environmental permitting requirements, reviews or approvals as required by federal, state or local law prior to the installation of such facilities. The Parties agree to coordinate environmental permitting related activities such as site review for regulated resources, permit application and project oversight (e.g. monitoring as applicable).

9.8 Whenever system modifications are required to connect generating facilities to either the Local Distribution Company's or the Transmission Owner's system it is expected that the party installing the generating facilities will normally be responsible for much or all of the associated costs. The Parties agree to cooperate in sharing information regarding such projects and to individually make arrangements with the party adding the generation to obtain payment of all related costs as appropriate.

ARTICLE 10. Access to Facilities

10.1 The Parties hereby agree to provide each other reasonable access to their respective property as may be necessary and appropriate to enable each Party to operate and maintain its respective facilities and equipment on such property. Such right of access shall be provided in a manner so as not to unreasonably interfere with either Party's ongoing business operations, rights, and obligations.

10.2 Each Party shall provide the other Party keys, access codes or other access methods necessary to enter the other Party's facilities to exercise rights under this Agreement. Access shall only be granted to Qualified Personnel.

ARTICLE 11. Notifications and Reporting

11.1 Unless otherwise provided, any notice required to be given by either Party to the other Party in connection with this Agreement shall be given in writing: (a) personally; (b) by facsimile transmission (if sender thereafter sends such notice to recipient by any of the other methods provided in this Section 11.1; (c) by registered or certified U.S. mail, return receipt requested, postage prepaid; or (d) by reputable overnight carrier, with acknowledged receipt of delivery; or (e) any other method mutually agreed by the Parties in writing. Notice shall be deemed given on the date of receipt personally. Notice sent by facsimile shall be deemed given on the date the transmission is confirmed by sender's facsimile machine, so long as the facsimile is sent on a business day during normal business hours of the recipient. Otherwise, the notice shall be deemed given on

the next succeeding business day. Notice provided by mail or overnight courier shall be deemed given at the date of acceptance or refusal of acceptance shown on such receipt.

11.2 Notice to the Transmission Owner shall be to the Transmission Owner's Representative, at the addresses identified in Exhibit 2. Notice to the Local Distribution Company shall be to the Local Distribution Company's Representative, at the addresses identified in Exhibit 2.

11.3 Each Party shall provide prompt notice describing the nature and extent of the condition, the impact on operations, and all corrective action, to the other Party of any Emergency or Network Security Condition which may be reasonably anticipated to affect the other Party's equipment, facilities, or operations. Either Party may take reasonable and necessary action, both on its own and the other Party's system, equipment, and facilities, to prevent, avoid or mitigate injury, danger, damage or loss to its own equipment and facilities, or to expedite restoration of service; provided however, that the Party taking such action shall give the other Party prior notice, if at all possible, before taking any action on the other Party's system, equipment, or facilities.

11.4 In the event of an Emergency or Network Security Condition contemplated by Section 11.3, each Party shall provide the other with such information, documents, and data necessary for operation of the Transmission System and Distribution System, including, without limitation, such information which is to be supplied to any Governmental Authority, NERC, ECAR, or Transmission System Operations Center or Distribution System Control Center.

11.5 In order to continue interconnection of the Distribution System and Transmission System, each Party shall promptly provide the other Party with all relevant information, documents, or data regarding the Distribution System and the Transmission System that would be expected to affect the Distribution System or Transmission System, and which is reasonably requested by NERC, ECAR, or any Governmental Authority.

11.6 For routine maintenance and inspection activities on either Parties system that will require major equipment or system outages, and could impact the other Party's system, the Party performing the same shall provide the other Party with not less than seventy-two (72) hours prior notice, if practicable; provided that the provisions of Section 3.9 remain applicable to the outages, and said notice is in addition to, and does not substitute for, the requirements of Section 3.9 (maintenance and inspection activities in generating plant substations require 20 working days notification).

11.7 Transmission Owner shall notify Local Distribution Company prior to entering Local Distribution Company's facilities for routine measurements, inspections and meter reads in accordance with the requirements of Section 11.6. Local Distribution Company shall notify Transmission Owner prior to entering

Transmission Owner's facilities, including switchyards, for routine maintenance, operations, measurements, inspections and meter reads, in accordance with the requirements of Section 11.6.

11.8 Each Party shall provide prompt verbal notice to the other Party of any system alarm that applies to the other Party's equipment, unless the system alarm is automatically sent to the other Party.

11.9 Each Party shall provide a report or a copy of the data from a system events recorder, SCADA system sequence of events or digital fault recorder that applies to the other Party's equipment.

11.10 Each Party agrees to immediately notify the other Party verbally, and then in writing, of any labor dispute or anticipated labor dispute of which its management has actual Knowledge that might reasonably be expected to affect the operations of the other Party with respect to this Agreement.

ARTICLE 12. Safety

12.1 Each Party agrees that all work performed by either Party that may reasonably be expected to affect the other Party shall be performed in accordance with Good Utility Practice and all applicable laws, regulations, safety standards, practices and procedures and other requirements pertaining to the safety of Persons or property, (including, but not limited to those of the Occupational Safety and Health Administration, the National Electrical Safety Code and those developed or accepted by Transmission Owner and Local Distribution Company for use on their respective systems) when entering or working in the other Party's property or facilities or switching area. A Party performing work within the boundaries of the other Party's facilities must abide by the safety rules applicable to the site.

12.2 Each Party shall be solely responsible for the safety and supervision of its own employees, agents, representatives, and subcontractors.

12.3 Transmission Owner shall immediately report any injuries that occur while working on the Local Distribution Company's property or facilities or switching area to appropriate agencies and the Local Distribution Company's Site Representative. Local Distribution Company shall immediately report any injuries that occur while working on the Transmission Owner's property or facilities or switching area to appropriate agencies and the Transmission Owner's Site Representative. Each Party will provide the other with its clearing/tagging/lockout procedures. For clearances requested or initiated by the Local Distribution Company on the Local Distribution Company's equipment that utilizes the Transmission Owner's equipment as an isolation device, Local Distribution Company procedures shall govern. For clearances requested or initiated by the Transmission Owner on the Transmission Owner's equipment that utilizes the Local Distribution Company's equipment as an isolation device,

Transmission Owner procedures shall govern. Under no circumstances shall either Party remove the other Party's protective tags without proper authorization.

ARTICLE 13. Environmental Compliance and Procedures

13.1 Release Prevention and Response. Each Party shall notify the other Party, verbally within 24 hours upon discovery of any Release of any Regulated Substance caused by the Party's operations or equipment that impacts the property or facilities of the other Party, or which may migrate to, or adversely impact the property, facilities or operations of the other Party and shall promptly furnish to the other Party copies of any reports filed with any governmental agencies addressing such events. Such verbal notification shall be followed by written notification within five (5) days. The Party responsible for the Release of any Regulated Substance on the property or facilities of the other Party, or which may migrate to, or adversely impact the property, facilities or operations of the other Party shall be responsible for: (1) the cost and completion of reasonable remediation or abatement activity for that Release, and; (2) required notifications to governmental agencies and submitting of all reports or filings required by environmental laws for that Release. Advance written notification (except in Emergency situations, in which verbal, followed by written notification, shall be provided as soon as practicable) shall be provided to the other Party by the Party responsible for any remediation or abatement activity on the property or facilities of the other Party, or which may adversely impact the property, facilities, or operations of the other Party. Except in Emergency situations such remediation or abatement activity shall be performed only with the consent of the Party owning the affected property or facilities.

13.2 The Parties agree to coordinate, to the extent necessary, the preparation of site plans, reports, environmental permits, clearances and notifications required by federal and state law or regulation, including but not limited to Spill Prevention, Control and Countermeasures (SPCC), Storm Water Pollution Prevention Plans (SWPP), Act 451 Part 31 Part 5 Rules, CERCLA, EPCRA, TSCA, soil erosion and sedimentation control plans (SESC) or activities, wetland or other water-related permits, threatened or endangered species reviews or management and archeological clearances or notifications required by any regulatory agency or competent jurisdiction. Notification of permits applied for and/or received will occur in a timeframe manner suitable to the interests of both Parties.

ARTICLE 14. Billings and Payment

14.1 Any invoices payable under this Agreement shall be provided to the other Party under this Agreement during the preceding month. Invoices shall be prepared within a reasonable time after the first day of each month. Each invoice shall delineate the month in which services were provided, shall fully describe the services rendered and shall be itemized to reflect the services performed or provided. The invoice shall be paid within twenty (20) days of the invoice date, or the first business day thereafter if the payment date falls on other than a

business day. All payments shall be made in immediately available funds payable to the other Party, or by wire transfer to a bank of the Party being paid, provided that payments expressly required by this Agreement to be mailed shall be mailed in accordance with Section 14.2.

14.2 Any payments required to be made by Local Distribution Company under this Agreement shall be made to Transmission Owner at the following address:

Michigan Electric Transmission Company, LLC
P.O. Box 673971
Detroit, MI 48267-3971

Any payments required to be made by Transmission Owner under this Agreement shall be made to Local Distribution Company at the following address:

Consumers Energy Company
One Energy Plaza
Jackson, MI 49201
Attention: Treasurer

14.3 The rate of interest on any amount not paid when due shall be equal to the Interest Rate in effect at the time such amount became due. Interest on delinquent amounts shall be calculated from the due date of the invoice to the date of the payment. When payments are made by mail, invoices shall be considered as having been paid on the date of receipt by the other Party. Nothing contained in this article is intended to limit either Party's remedies under Article 21 of this Agreement.

14.4 Payment of an invoice shall not relieve the paying Party from any responsibilities or obligations it has under this Agreement, nor shall such payment constitute a waiver of any claims arising hereunder.

14.5 If all or part of any bill is disputed by a Party, that Party shall promptly pay the amount that is not disputed and provide the other Party a reasonably detailed written explanation of the basis for the dispute pursuant to Article 26. While the dispute is being resolved, the Parties shall continue to provide services and pay all invoiced amounts not in dispute. Following resolution of the dispute, the prevailing Party shall be entitled to receive the disputed amount, as finally determined to be payable, along with interest accrued at the Interest Rate through the date on which payment is made, within ten (10) business days of such resolution.

14.6 Subject to the Confidentiality provisions of Article 20, within two (2) years following a calendar year, during normal business hours, Local Distribution Company and Transmission Owner shall have the right to audit each other's accounts and records pertaining to transactions under this Agreement that occurred during such calendar year at the offices where such accounts and records are maintained; provided that the audit shall be limited to those portions

of such accounts and records that reasonably relate to the services provided to the other Party under this Agreement for said calendar year. The Party being audited shall be entitled to review the audit report and any supporting materials. To the extent that audited information includes Confidential Information, the auditing Party shall keep all such information confidential pursuant to Article 20.

14.7 Neither Party shall be responsible for the other Party's costs of collecting amounts due under this Agreement, including attorney fees and expenses and the expenses of arbitration.

ARTICLE 15. Applicable Regulations and Interpretation

15.1 Each Party's performance under this Agreement is subject to the condition that all requisite governmental and regulatory approvals for such performance are obtained in form and substance satisfactory to the other Party in its reasonable judgment. Each Party shall exercise Due Diligence and shall act in good faith to secure all appropriate approvals in a timely fashion.

15.2 This Agreement and all rights, obligations, and performances of the Parties hereunder, are subject to present or future state or federal laws, regulations, or orders properly issued by state or federal bodies having jurisdiction. When not in conflict with or pre-empted by federal law, this Agreement shall be interpreted pursuant to the laws of the State of Michigan, exclusive of its conflicts of law principles.

ARTICLE 16. Force Majeure

16.1 An event of Force Majeure means any act of God, labor disturbance, act of the public enemy, war, insurrection, riot, fire, storm or flood, explosion, breakage or accident to machinery or equipment, any curtailment, order, regulation, or restriction imposed by governmental military or lawfully established civilian authorities, or any other cause beyond a Party's reasonable control. A Force Majeure event does not include an act of negligence or intentional wrongdoing.

16.2 If either Party is rendered unable, wholly or in part, by Force Majeure, to carry out its obligations under this Agreement, then, during the continuance of such inability, the obligation of such Party shall be suspended except that Transmission Owner's and Local Distribution Company's obligation under Section 16.3 of this Agreement to provide protection shall not be suspended. The Party relying on Force Majeure shall give written notice of Force Majeure to the other Party as soon as practicable after such event occurs. Upon the conclusion of Force Majeure, the Party heretofore relying on Force Majeure shall, with all reasonable dispatch, take all necessary steps to resume the obligation previously suspended.

16.3 Any Party's obligation to make payments already owing shall not be suspended by Force Majeure.

ARTICLE 17. Indemnification and Limitation on Liability

17.1 Each Party shall at all times assume all liability for, and shall indemnify and save the other Party harmless from any and all damages, losses, claims, demands, suits, recoveries, costs, legal fees, expenses for injury to or death of any Person or Persons whomsoever, or for any loss, destruction of or damage to any property of third persons, firms, corporations or other entities that occurs on its own system and that arises out of or results from, either directly or indirectly, its own facilities or facilities controlled by it, unless caused by the sole negligence, or intentional wrongdoing, of the other Party.

17.2 NEITHER PARTY SHALL BE LIABLE TO THE OTHER FOR ANY SPECIAL, INCIDENTAL, EXEMPLARY, PUNITITIVE OR CONSEQUENTIAL DAMAGES SUCH AS, BUT NOT LIMITED TO, LOST PROFITS, REVENUE OR GOOD WILL, INTEREST, LOSS BY REASON OF SHUTDOWN OR NON-OPERATION OF EQUIPMENT OR MACHINERY, INCREASED EXPENSE OF OPERATION OF EQUIPMENT OR MACHINERY, COST OF PURCHASED OR REPLACEMENT POWER OR SERVICES OR CLAIMS BY CUSTOMERS, WHETHER SUCH LOSS IS BASED ON CONTRACT, WARRANTY, NEGLIGENCE, STRICT LIABILITY OR OTHERWISE.

ARTICLE 18. Insurance

18.1 The Parties agree to maintain, at their own cost and expense, the following insurance coverages for the life of this Agreement in the manner and amounts, at a minimum, as set forth below:

(a) Workers' Compensation Insurance in accordance with all applicable State, Federal, and Maritime Law.

(b) Employer's Liability insurance in the amount of $1,000,000 per accident.

(c) Commercial General Liability or Excess Liability Insurance in the amount of $25,000,000 per occurrence.

(d) Automobile Liability Insurance for all owned, non-owned, and hired vehicles in the amount of $5,000,000 each accident.

18.2 A Party may, at its option, [A] be an approved self-insurer by the State of Michigan for the insurances required in 1.(a) and (d); and [B] maintain such deductibles and/or retentions under the insurance required in 1.(b) and (c) as is maintained by other similarly situated companies engaged in a similar business. The Parties agree that all amounts of self-insurance, retentions and/or deductibles are the responsibility of, and shall be borne by, the Party whom makes such an election.

18.3 Within fifteen (15) days of the Effective Date and thereafter when requested, in writing, but not more than once every 12 months, during the term of this

Agreement (including any extensions) each Party shall provide to the other Party properly executed and current certificates of insurance or evidence of approved self-insurance status with respect to all insurance required to be maintained by such Party under this Agreement. Certificates of insurance shall provide the following information:

(a) Name of insurance company, policy number and expiration date.

(b) The coverage maintained and the limits on each, including the amount of deductibles or retentions, which shall be for the account of the Party maintaining such policy.

(c) The insurance company shall endeavor to provide thirty (30) days prior written notice of cancellation to the certificate holder.

ARTICLE 19. Several Obligations

19.1 Except where specifically stated in this Agreement to be otherwise, the duties, obligations and liabilities of the Parties are intended to be several and not joint or collective. Nothing contained in this Agreement shall ever be construed to create an association, trust, partnership, or joint venture or to impose a trust or partnership duty, obligation or liability or agency relationship on or with regard to either Party. Each Party shall be individually and severally liable for its own obligations under this Agreement.

ARTICLE 20. Confidentiality

20.1 (a) "Confidential Information" shall mean any confidential, proprietary or trade secret information of a plan, specification, pattern, procedure, design, device, list concept, policy or compilation relating to the present or planned business of a Party, which is designated in good faith as Confidential by the Party supplying the information, whether conveyed orally, electronically, in writing, through inspection or otherwise. Confidential Information shall include, without limitation, all information relating to a Party's technology, research and development, business affairs, and pricing, customer-specific load data that constitutes a trade secret, and any information supplied by either of the Parties to the other prior to the execution of this Agreement.

(b) General. Each Party will hold in confidence any and all Confidential Information unless (1) compelled to disclose such information by judicial or administrative process or other provisions of law or as otherwise provided for in this Agreement, or (2) to meet obligations imposed by FERC or by a state or other federal entity or by membership in NERC or ECAR (including other Transmission Owners). Information required to be disclosed under (b)(1) or (b)(2) above, does not, by itself, cause any information provided by Local Distribution Company to Transmission Owner to lose its confidentiality. To the extent it is necessary for either Party to release or disclose such information to a third party in order to perform that Party's obligations herein,

such Party shall advise said third party of the confidentiality provisions of this Agreement and use its best efforts to require said third party to agree in writing to comply with such provisions. Each party will develop and file with FERC standards of conduct relating to the sharing of a market-related Confidential Information with and by their employees.

(c) Term: During the term of this Agreement, and for a period of three (3) years after the expiration or termination of this Agreement, except as otherwise provided in this Article 20, each Party shall hold in confidence and shall not disclose to any Person Confidential Information.

(d) Standard of Care: Each Party shall use at least the same standard of care to protect Confidential Information it receives as that it uses to protect its own Confidential Information from unauthorized disclosure, publication or dissemination.

20.2 Scope: Confidential Information shall not include information that the receiving Party can demonstrate: (1) is generally available to the public other than as a result of disclosure by the receiving Party; (2) was in the lawful possession of the receiving Party on a non-confidential basis prior to receiving it from the disclosing Party; or (3) was supplied to the receiving Party without restriction by a third party, who, to the Knowledge of the receiving Party, after due inquiry was under no obligation to the disclosing Party to keep such information confidential; (4) was independently developed by the receiving Party without reference to Confidential Information of the disclosing Party; (5) is, or becomes, publicly known, through no wrongful act or omission of the receiving Party or breach of this Agreement; or (6) is required, in accordance with Section 20.1(b) of this Agreement, to be disclosed by any federal or state government or agency or is otherwise required to be disclosed by law or subpoena, or is necessary in any legal proceeding establishing rights and obligations under this Agreement. Information designated as Confidential Information will no longer be deemed confidential if the Party that designated the information as confidential notifies the other Party that it no longer is confidential.

20.3 Order of Disclosure. If a court or a government agency or entity with the right power, and apparent authority to do so requests or requires either Party, by subpoena, oral deposition, interrogatories, requests for production of documents, administrative order, or otherwise, to disclose Confidential Information, that Party shall provide the other Party with prompt notice of such request(s) or requirement(s) so that the other Party may seek an appropriate protective order or waive compliance with the terms of this Agreement. The notifying Party shall have no obligation to oppose or object to any attempt to obtain such production except to the extent requested to do so by the disclosing Party and at the disclosing Party's expense. If either Party desires to object or oppose such production, it must do so at its own expense. The disclosing Party may request a protective order to prevent any Confidential Information from being made public. Notwithstanding the absence of a protective order or waiver, the Party may

disclose such Confidential Information which, in the opinion of its counsel, the Party is legally compelled to disclose. Each Party will use reasonable effort to obtain reliable assurance that confidential treatment will be accorded any Confidential Information so furnished.

20.4 Use of Information or Documentation. Each Party may utilize information or documentation furnished by the disclosing Party and subject to Section 20.1 in any proceeding under Article 26 or in an administrative agency or court of competent jurisdiction addressing any dispute arising under this Agreement, subject to a confidentiality agreement with all participants (including, if applicable, any arbitrator) or a protective order.

20.5 Remedies Regarding Confidentiality. The Parties agree that monetary damages by themselves will be inadequate to compensate a Party for the other Party's breach of its obligations under this article. Each Party accordingly agrees that the other Party is entitled to equitable relief, by way of injunction or otherwise, if it breaches or threatens to breach its obligations under this article.

ARTICLE 21. Breach, Default and Remedies

21.1 General. A breach of this Agreement ("Breach") shall occur upon the failure by a Party to perform or observe a material term or condition of this Agreement. A default of this Agreement ("Default") shall occur upon the failure of a Party in Breach of this Agreement to cure such Breach in accordance with Section 21.4.

21.2 Events of Breach. A Breach of this Agreement shall include:

(a) The failure to pay any amount when due;

(b) The failure to comply with any material term or condition of this Agreement, including but not limited to any material Breach of a representation, warranty or covenant made in this Agreement;

(c) A Party's abandonment of its work or the facilities contemplated in this Agreement;

(d) If a Party: (1) becomes insolvent; (2) files a voluntary petition in bankruptcy under any provision of any federal or state bankruptcy law or shall consent to the filing of any bankruptcy or reorganization petition against it under any similar law; (3) makes a general assignment for the benefit of its creditors; or (4) consents to the appointment of a receiver, trustee or liquidator;

(e) Failure of either Party to provide information or data to the other Party as required under this Agreement, provided the Party entitled to the information or data under this Agreement requires such information or data to satisfy its obligations under this Agreement.

21.3 Continued Operation. Except as specifically provided in this Agreement, in the event of a Breach or Default by either Party, the Parties shall continue to operate and maintain, as applicable, facilities and appurtenances that are reasonably necessary for the Transmission Owner to operate and maintain the Transmission System, or the Local Distribution Company to operate and maintain the Distribution System, in a safe and reliable manner.

21.4 Cure and Default. Upon the occurrence of an event of Breach, the non-Breaching Party, when it becomes aware of the Breach, shall give written notice of the Breach to the Breaching Party and to any other Person a Party to this Agreement identifies in writing to the other Party in advance. Such notice shall set forth, in reasonable detail, the nature of the Breach, and where known and applicable, the steps necessary to cure such Breach. Upon receiving written notice of the Breach hereunder, the Breaching Party shall have thirty (30) days, to cure such Breach. If the breach is such that it cannot be cured within thirty (30) days, the Breaching Party will commence in good faith all steps as are reasonable and appropriate to cure the Breach within such thirty (30) day time period and thereafter diligently pursue such action to completion. In the event the Breaching Party fails to cure the Breach, or to commence reasonable and appropriate steps to cure the Breach, within thirty (30) days of becoming aware of the Breach, the Breaching Party will be in Default of the Agreement. In the event of a Default, the non-Defaulting Party has the right to take whatever action at law or equity as may be permitted under this Agreement.

21.5 Right to Compel Performance. Notwithstanding the foregoing, upon the occurrence of an event of Default, the non-Defaulting Party shall be entitled to Commence an action to require the Defaulting Party to remedy such Default and specifically perform its duties and obligations hereunder in accordance with the terms and conditions hereof, and exercise such other rights and remedies as it may have in equity or at law.

ARTICLE 22. Term

22.1 Term. This Agreement shall become effective as of the Effective Date and shall continue in full force and effect so long as any Interconnection Point is connected to the Transmission System, except that it may be terminated by mutual agreement of the Parties.

22.2 Material Adverse Change.

(a) In the event of a material change in law or regulation that adversely affects, or may reasonably be expected to adversely affect, either Party's performance under this Agreement, including but not limited to the following:

(i) this Agreement is not accepted for filing by the FERC without material modification or condition;

(ii) NERC or ECAR prevents, in whole or in part, either Party from performing any provision of this Agreement in accordance with its terms; or

(iii) The FERC, the United States Congress, any state, or any federal or state regulatory agency or commission implements any change in any law, regulation, rule or practice which materially affects or is reasonably expected to materially affect either Party's ability to perform under this Agreement.

The Parties will negotiate in good faith any amendment or amendments to the Agreement necessary to adapt the terms of this Agreement to such change in law or regulation, and the Transmission Owner shall file such amendment or amendments with FERC.

(b) If the Parties are unable to reach agreement on any such amendments, then the Parties shall continue to perform under this Agreement to the maximum extent possible, taking all reasonable steps to mitigate any adverse effect on each other resulting from the Event. If the Parties are unable to reach agreement on any such amendments, Transmission Owner shall have the right to make a unilateral filing with FERC to modify this Agreement pursuant to Section 205 of the Federal Power Act and Local Distribution Company shall have the right to make a unilateral filing with FERC to modify this Agreement pursuant to Section 206 of the Federal Power Act. Each Party shall have the right to protest any such filing by the other Party and to participate fully in any proceeding before FERC.

22.3 Survival. The applicable provisions of this Agreement shall continue in effect after expiration, cancellation or termination hereof to the extent necessary to provide for final billings, billing adjustments and the determination and enforcement of liability and indemnification obligations arising from acts or events that occurred while this Agreement was in effect.

ARTICLE 23. Assignment/Change in Corporate Identity

23.1 Transmission Owner Assignment Rights. Transmission Owner may not assign this Agreement or any of its rights, interests, or obligations hereunder without the prior written consent of Local Distribution Company, which consent shall not be unreasonably withheld; provided however, that Transmission Owner may assign this Agreement or any of its rights or obligations hereunder without the prior consent of Local Distribution Company and may assign this Agreement to any entity(ies) in connection with a merger, consolidation, or reorganization, provided that the surviving entity(ies) or assignee owns the Transmission System, agrees in writing to be bound by all the obligations and duties of Transmission Owner provided for in this Agreement and the assignee's creditworthiness is equal to or higher than that of Transmission Owner.

23.2 Local Distribution Company Assignment Rights. Local Distribution Company may not assign this Agreement or any of its rights, interests or obligations hereunder without the prior written consent of Transmission Owner, which consent shall not be unreasonably withheld; provided however, that Local Distribution Company may, without the consent of Transmission Owner, and by providing prior reasonable notice under the circumstances to Transmission Owner, assign, this Agreement to any entity(ies) in connection with a merger, consolidation, or reorganization, provided that the surviving entity(ies) or assignee owns the Local Distribution Company, agrees in writing to be bound by all the obligations and duties of Local Distribution Company provided for in this Agreement and the assignee's creditworthiness is equal to or higher than that of Local Distribution Company.

23.3 Assigning Party to Remain Responsible. Any assignments authorized as provided for in this article will not operate to relieve the Party assigning this Agreement or any of its rights, interests, or obligations hereunder of the responsibility of full compliance with the requirements of this Agreement unless (a) the other Party consents, such consent not to be unreasonably withheld, and (b) the assignee agrees in writing to be bound by all of the obligations and duties of the assigning Party provided for in this Agreement.

23.4 This Agreement and all of the provisions hereof are binding upon, and inure to the benefit of, the Parties and their respective successors and permitted assigns.

ARTICLE 24. Subcontractors

24.1 Nothing in this Agreement shall prevent the Parties from utilizing the services of subcontractors as they deem appropriate; provided, however, the Parties agree that, where applicable, all said subcontractors shall comply with the terms and conditions of this Agreement.

24.2 Except as provided herein, the creation of any subcontract relationship shall not relieve the hiring Party of any of its obligations under this Agreement. Each Party shall be fully responsible to the other Party for the acts and/or omissions of any subcontractor it hires as if no subcontract had been made. Any obligation imposed by this Agreement upon the Parties, where applicable, shall be equally binding upon and shall be construed as having application to any subcontractor.

24.3 No subcontractor is intended to be or shall be deemed a third-party beneficiary of this Agreement.

24.4 The obligations under this Article shall not be limited in any way by any limitation on subcontractor's insurance.

24.5 Each Party shall require its subcontractors to comply with all federal and state laws regarding insurance requirements and shall maintain standard and ordinary insurance coverages.

ARTICLE 25. Dispute Resolution

Any dispute between the parties arising out of or relating to this Contract or the breach thereof shall be brought to the Administrative Committee. If the Administrative Committee can resolve the dispute, such resolution shall be reported in writing to and shall be binding upon the Parties. If the Administrative Committee cannot resolve the dispute within a reasonable time, the senior officer of Local Distribution Company or the senior officer of Transmission Owner may, by written notice to the senior officer of the other Party and the members of the Administrative Committee, withdraw the matter from consideration by the Administrative Committee and submit the same for resolution to the senior officers of the Parties. If the senior officers of the Parties agree to a resolution of the matter, such resolution shall be reported in writing to, and shall be binding upon, the Parties; but if said senior officers fail to resolve the matter within five (5) Business Days after its submission to them, then the Parties agree to try in good faith to settle the dispute by mediation administered by the American Arbitration Association under its Commercial Mediation Rules before resorting to litigation.

ARTICLE 26. Miscellaneous Provisions

26.1 This Agreement shall constitute the entire Agreement between the Parties hereto relating to the subject matter hereof. In all other respects, special contracts or superseding rate schedules shall govern Transmission Owner's transmission service to Local Distribution Company.

26.2 No failure or delay on the part of Transmission Owner or Local Distribution Company in exercising any of its rights under this Agreement, no partial exercise by either Party of any of its rights under this Agreement, and no course of dealing between the Parties shall constitute a waiver of the rights of either Party under this Agreement. Any waiver shall be effective only by a written instrument signed by the Party granting such waiver, and such shall not operate as a waiver of, or estoppel with respect to, any subsequent failure to comply therewith.

26.3 Nothing in this Agreement, express or implied, is intended to confer on any other Person except the Parties hereto any rights, interests, obligations, or remedies hereunder.

26.4 In the event that any clause or provision of this Agreement or any part hereof shall be held to be invalid, void, or unenforceable by any court or Governmental Authority of competent jurisdiction, said holding or action shall be strictly construed and shall not affect the validity or effect of any other provision hereof, and the Parties shall endeavor in good faith to replace such invalid or unenforceable provisions with a valid and enforceable provision which achieves the purposes intended by the Parties to the greatest extent permitted by law.

26.5 The article and section headings herein are inserted for convenience only and are not to be construed as part of the terms hereof or used in the interpretation of this Agreement.

26.6 In the event an ambiguity or question of intent or interpretation arises, this Agreement shall be construed as if drafted jointly by the Parties and no presumption or burden of proof shall arise favoring or disfavoring any Party by virtue of authorship of any of the provisions of this Agreement. Any reference to any federal, state, local, or foreign statute or law shall be deemed also to refer to all rules and regulations promulgated thereunder, unless the context requires otherwise. The word “including” in this Agreement shall mean including without limitation.

26.7 This Agreement may be executed in one or more counterparts, each of which shall be deemed an original.

26.8 Each Party shall act as an independent contractor with respect to the provision of services hereunder.

IN WITNESS WHEREOF, Transmission Owner and Local Distribution Company have caused this instrument to be executed by their duly authorized representatives as of the day and year first above written.

Review and Approval	Initial	
JR McCormick		12/17/2024 | 1:34 PM EST
ML Hayward	DS	12/17/2024 | 1:36 PM EST
SJ Herrygers	SH	12/17/2024 | 1:44 PM EST
Approval as to Form		
Legal	RM	12/17/2024 | 1:[illegible]

CONSUMERS ENERGY COMPANY

Name: Tonya Berry

Title: Senior Vice President Transformation and Engineering

Signed by: Tonya Berry BEAA3C1321D54C4... 12/17/2024 | 1:55 PM

MICHIGAN ELECTRIC TRANSMISSION COMPANY, LLC, a Michigan limited liability company

By: ITC Holdings Corp., a Michigan corporation, its sole manager

By: DocuSigned by: 357A7F23DA6542F... 12/29/2024 | 9:08:25 PM EST

Name: Brian Slocum

Title: Senior Vice President and Chief Operating Officer

EXHIBIT 1 – Interconnection Points (Substations)

Addendum 14 - October 18, 2024

Substation

1. Abbe
2. Acme (04/10)
3. Alcona
4. Alder Creek
5. Alger
6. Algoma
7. **Alliance (05/24)**
8. Alma
9. Almeda
10. Alpena
11. Alpine
12. Amber
13. American Bumper
14. Arenac (05/23)
15. Arthur (06/06)
16. Ash Road (06/18)
17. Aubil Lake
18. Backus
19. Bagley
20. Bangor
21. Baraga (12/07)
22. Bard Road
23. Barnum Creek
24. Barry
25. Bass Creek
26. Batavia
27. Bay Road
28. Bayberry
29. Beals Road
30. Becker
31. Beaver Creek
32. Beebe
33. Beecher
34. Begole
35. Bell Road
36. Bennington
37. Benston (11/18)
38. Beveridge
39. Bilmar
40. Bingham
41. Birchwood (06/12)
42. Black River
43. Blackman
44. Blackstsone
45. Blinton
46. Blue Water
47. Bluegrass
48. Boardman
49. Boxboard
50. Bricker
51. Brickyard
52. Briggs & Stratton
53. Broadmoor
54. Bronco
55. Broughwell
56. Buck Creek
57. Bullock
58. Busch Road (02/08)
59. Caledonia
60. Calhoun
61. Camelot Lake
62. Campbell 138
63. Canal
64. Cannon
65. Carpenter Rd (08/06)
66. Carter
67. Cedar Springs
68. **Celery (03/24)**
69. Cement City
70. **Charge (05/24)**
71. Chase
72. Cheesman
73. Chicago
74. Churchill
75. Clare
76. Claremont
77. Clearwater
78. Cleveland
79. Club
80. Cobb
81. Cochran
82. Cole Creek

83. Colony Farm
84. Convis
85. Cork Street
86. Cornell
87. Cottage Grove
88. Covert
89. Cowan Lake
90. Crahen (10/07)
91. Croton
92. David
93. Dean Road
94. Deja
95. Delaney
96. Delhi
97. Denso Jackson
98. Derby
99. Discovery Way (04/11)
100. Dorr Corners
101. Dort
102. Dow Corning
103. Dowling
104. Drake Road
105. Duffield Rd
106. Dupont
107. Duquite
108. Dutton
109. East Paris
110. East Tawas
111. Easton
112. Edenville
113. Edwards (07/21)
114. Ellis
115. Elm Street
116. Elmwood
117. Emmet
118. Englishville
119. Eureka
120. Farr Road
121. Felch Road
122. Filer City
123. Fillmore
124. Flakeboard
125. Forest (12/16)
126. Forest Grove (12/18)
127. Fort Custer
128. Forty Fourth Street
129. Four Mile
130. Gaylord
131. Geddes (04/08)
132. Gleaner
133. Grand Blanc BOC
134. Gratiot
135. Greenwood
136. Grey Iron
137. Grodi Road
138. Gout
139. Hackett
140. Hagadorn
141. Hager Park
142. Halsey
143. Haring
144. Harvard Lake (06/09)
145. Hawthorne (11/22)
146. Hazelwood
147. Hemphill
148. Hendershot
149. Higgins
150. Hile Road
151. Hillman Cogen
152. Hodenpyl
153. Holland Road
154. Hotchkiss
155. Howell Road (12/21)
156. HSC
157. Hubbard Lake (12/07)
158. Huckleberry (05/22)
159. Hubbardston Road (06/10)
160. Hudsonville
161. Hughes Road
162. Hull Street
163. Iosco
164. Island Road
165. Jamestown
166. Karn 138
167. Kentwood
168. Keystone
169. Kinderhook (05/07)
170. Kipp Road
171. Kraft Avenue
172. Kromdyke (04/19)
173. Labarge
174. Lafayette
175. Latimer
176. Laundra (05/07)
177. Lawndale
178. Layton
179. Letts Road
180. Lewiston
181. Lindbergh
182. Livingston Peaker

183. Looking Glass
184. Lorin
185. Lovejoy
186. Ludington
187. Maines Road (03/17)
188. Manlius
189. Marquette
190. McGulpin
191. McNally
192. MCV
193. Meadowbrooke
194. Mecosta
195. Medusa
196. Michigan
197. Michigan Power (MPLP)
198. Miles Road
199. Milham
200. Mio
201. Monitor
202. Moore Road
203. Mullins
204. Murner (10/19)
205. Muskegon Heights
206. Neff Road
207. Nineteen Mile Road
208. North Belding
209. North Corunna
210. Northern Fibre
211. North Star (02/19)
212. Nugent Sand
213. Oakland
214. Oceana
215. Ogemaw
216. Orr Road (03/09)
217. Owosso
218. Packard
219. Page Avenue
220. Palisades
221. Parkville (08/12)
222. Parr Road
223. Parshallville
224. Pasadena
225. Pavilion
226. Pearline (06/11)
227. Pettis Road
228. Pigeon River/Rondo
229. Pingree (10/08)
230. Piston Ring P
231. Plaster Creek
232. Plum (07/10)
233. Plymouth Street
234. Plywood
235. Polkton (11/22)
236. Port Calcite
237. Port Sheldon
238. Porter
239. Portsmouth
240. Price Road (09/07)
241. Progress Street
242. Race Street
243. Raisin
244. Ransom
245. Ratigan (12/12)
246. Regal (01/13)
247. Renaissance
248. Rice Creek
249. Rifle River
250. Riggsville
251. **Riverbend (12/24)**
252. Rivertown
253. Riverview
254. Roedel Road
255. Rogue River (06/07)
256. Ryno (09/14)
257. Saginaw River
258. Samaria
259. Sanderson
260. **Santiago (12/24)**
261. Savidge
262. Scenic Lake (12/15)
263. Scott Lake
264. Seamless East/Seamless
265. Seven Mile (11/2020)
266. Simmons
267. Simpson (08/12)
268. Smith Creek
269. Snyder (06/17)
270. Sonoma (05/06)
271. Spaulding
272. Spruce Road
273. Stacey
274. Steelcase
275. Stillson
276. Stonegate
277. Stover
278. Stronach
279. Summerton
280. Tallman
281. Technical Drive (01/20)
282. Thetford

283. Thompson Road
284. Tihart
285. Tinsman
286. Tippy
287. Titus Lake
288. Trillium (06/07)
289. Trowbridge
290. Tuscola Bay
291. Twelfth Street
292. Twilight
293. Upjohn
294. Van Atta
295. Van Buren (06/08)
296. Vanderbilt
297. Vernon
298. Verona
299. Vevay
300. Viking Lincoln
301. Vrooman
302. Wakerly
303. Warner
304. Warren
305. Washtenaw
306. Wayland
307. Weadock
308. Wealthy Street
309. West Fenton (05/07)
310. Wexford
311. White Lake
312. White Road
313. Whiting
314. Whittemore
315. Willard
316. Withey Lake (05/06)
317. Zeeland

New Interconnections added for this year's DTIA are shown in **bold type**.

Interconnections added after May of 2002 will have the (month/year) in-service date after the substation name.

Note, this list of substations is not necessarily a list of the true points of facility ownership change between the Transmission Owner and the Local Distribution Company. This also is not a complete listing of all Local Distribution Company substations that have a 138 kV high-side supply voltage.

The generator sites or generator POIs referenced under this Exhibit are referenced herein because Local Distribution Company provides distribution service to the corresponding generators.

EXHIBIT 2 - Contact Information For Local Distribution Company's Representatives and Transmission Owner's Representatives

Local Distribution Company:

Consumers Energy Company
1945 West Parnall Road
Jackson, MI 49201

Attn: Executive Director, Electric Planning

Transmission Owner:

Michigan Electric Transmission Company, LLC
27175 Energy Way
Novi, MI 48377

Attn: Legal Department – General Counsel

Email: jdanna@itctransco.com

EXHIBIT 3

Intentionally Omitted

EXHIBIT 4 – Metering Specifications

Performance criteria:

1. Meters shall meet or exceed the latest version of ANSI C12.16 (Standard for Solid State Electricity Meters) specifications for solid state metering.

2. Current transformers used for metering shall meet or exceed an accuracy class of 0.3%. Secondary connected burdens shall not exceed rated burden of any current transformer. Current transformers shall comply with most current applicable ANSI Standards including C57.13 (IEEE Standard Requirements for Instrument Transformers) and C12.11 (Instrument Transformers for Revenue Metering 10 kV BIL through 350 kV BIL). Meter installations shall comply with manufacturer's accuracy and burden class information on the nameplate of each device.

3. Voltage transformers used for metering shall meet or exceed an accuracy class of 0.3%. Secondary connected burdens shall not exceed rated burden of any voltage transformer. Voltage transformers shall comply with most current applicable ANSI Standards including C57.13 (IEEE Standard Requirements for Instrument Transformers), and C12.11 (Instrument Transformers for Revenue Metering 10 kV BIL through 350 kV BIL). Meter installations shall comply with manufacturer's accuracy and burden class information on the nameplate of each device.

4. PT secondary circuits shall have a disconnect switch installed which provides a visible air gap for worker safety, and which allows for attachment of a protective safety tag.

EXHIBIT 5

Intentionally Omitted

EXHIBIT 6 - Jointly Owned Assets Ownership by Percent of Major Equipment
Addendum 14 – October 18, 2024

Substations

Jointly Owned Assets, Percentage Split by Major Equipment Count[1]

Substation Name	Distribution owned by Local Distribution Company	Transmission owned by Transmission Owner	Generation Owned by Local Distribution Company	Third-Party Assets	Last Revision Date
Alder Creek	99.99	0.01			4/15/19
Alma	66.67	33.33			10/24/03
Amber	66.67	33.33			4/15/19
Bangor	33.33	66.67			4/15/19
Bard Road	41.67	58.33			06/10/10
Bass Creek	83.33	16.67			4/15/19
Batavia	53.33	46.67			11/17/22
Bay Road	99.99	0.01			4/15/19
Beals Road	84.62	15.38			06/10/10
Beaver Creek	66.67	33.33			07/15/20
Beecher	77.42	22.58			11/17/22
Bell Road	99.99	0.01			4/15/19
Bennington	99.99	0.01			4/15/19
Beveridge	80.00	20.00			4/15/19
Bingham	57.14	42.86			11/7/23
Black River	66.67	33.33		0.00	4/15/19
Blackman	99.99	0.01			4/15/19
Blackstone	70.83	29.17			11/28/11

1 Notes:

(a) Transmission Owner shall own at least 0.01% of all jointly owned substations regardless of its status regarding ownership of major equipment.

(b) Changes, relative to the previous revision (addendum), are shown in bold type.

(c) At 120kV and above, third-party related assets will be included as part of the Transmission Owner's assets for purposes of making this calculation. Also, the third-party may share in the financial responsibility associated with O&M activities.

(d) Third-party may share in the financial responsibility associated with O&M activities.

(e) Below 120kV the third-party related assets will be included as part of the Local Distribution Company's assets for purposes of making this calculation. Also, the third-party may share in the financial responsibility associated with O&M activities.

Blinton	99.99	0.01			4/15/19
Broadmoor	95.83	4.17			4/15/19
Broughwell	99.99	0.01			4/15/19
Buck Creek	58.33	41.67			11/17/22
Bullock	76.00	24.00			11/20/08
Chase	62.50	37.50			4/15/19
Claremont	68.00	32.00			05/01/02
Cobb	57.69	42.31	0.00		07/15/20
Cork Street	33.33	66.67			4/15/19
Cornell	66.67	33.33			11/27/23
Cottage Grove	99.99	0.01			4/15/19
Croton	59.09	31.82	9.09		4/15/19
Dean Road	99.99	0.01			4/15/19
Delaney	80.00	20.00			4/15/19
Delhi	52.38	47.62			10/02/14
Dort	**99.99**	**0.01**			**10/18/24**
Dow Corning	80.00	20.00			4/15/19
Drake Road	99.99	0.01			4/15/19
Dupont	99.99	0.01			4/15/19
Duquite	99.99	0.01			4/15/19
East Paris	99.99	0.01			4/15/19
East Tawas	99.99	0.01			4/15/19
Emmet	61.54	38.46			4/15/19
Eureka	60.00	40.00			11/7/23
Felch Road	83.33	16.67			03/31/06
Four Mile	**88.00**	**12.00**			**10/18/24**
Gaylord	55.56	44.44	0.00		4/15/19
Grand Blanc BOC	25.00	75.00			4/15/19
Grey Iron	80.00	20.00			4/15/19
Halsey	76.92	23.08			10/24/03
Hazelwood	85.71	14.29			4/15/19
Hemphill	65.52	34.48			11/27/23
Higgins	68.75	31.25			11/7/23
Holland Road	75.00	25.00			4/15/19
Hotchkiss	99.99	0.01			4/15/19
HSC	33.33	66.67			11/28/11
Iosco	75.00	25.00			4/15/19
Island Road	76.92	23.08			4/15/19
Kentwood	99.99	0.01			4/15/19
Kipp Road	99.99	0.01			4/15/19
Kraft Avenue	99.99	0.01			4/15/19
Lafayette	99.99	0.01			4/15/19
Lawndale	70.59	29.41			11/28/12
Layton	99.99	0.01			4/15/19

Lindbergh	99.99	0.01			4/15/19
Manlius	99.99	0.01			4/15/19
Marquette	61.54	38.46			4/15/19
McGulpin	55.56	44.44			11/28/11
Mecosta	66.67	33.33			4/15/19
Milham	66.67	33.33			11/28/12
Monitor	86.67	13.33			4/15/19
Moore Road	50.00	36.36		13.64	11/17/22
North Belding	66.67	33.33			10/24/03
Oakland	62.50	37.50			4/15/19
Parr Road	85.71	14.29			4/15/19
Port Calcite	77.78	22.22			4/15/19
Ransom	72.73	27.27			11/23/21
Rice Creek	82.35	17.65			11/27/23
Riggsville	71.43	28.57			11/7/23
Riverview	63.16	36.84			11/23/21
Saginaw River	42.86	57.14			4/15/19
Samaria	90.00	10.00			4/15/19
Scott Lake	77.78	22.22			11/17/22
Spaulding	53.33	46.67			10/02/14
Spruce Road	99.99	0.01			4/15/19
Stover	37.50	62.50			11/23/21
Summerton	91.67	8.33			4/15/19
Tihart	66.67	33.33			11/28/12
Tippy	0.00	66.67	33.33		4/15/19
Upjohn	75.00	25.00			4/15/19
Vanderbilt	99.99	0.01			4/15/19
Verona	56.52	43.48			07/15/20
Vevay	99.99	0.01			4/15/19
Vrooman	62.50	37.50			4/15/19
Wackerly	90.00	10.00			4/15/19
Warner	99.99	0.01			4/15/19
Warren	81.82	18.18			4/15/19
Weadock	59.09	40.91	0.00		4/15/19
Wealthy Street	85.71	14.29			4/15/19
Wexford	85.71	14.29			4/15/19
White Lake	82.35	17.65			11/17/22
White Road	99.99	0.01			4/15/19
Whiting	53.85	46.15	0.00		4/15/19
Whittemore	99.99	0.01			4/15/19

TAB B

AMENDED AND RESTATED DISTRIBUTION-TRANSMISSION INTERCONNECTION AGREEMENT

by and between

Michigan Electric Transmission Company, LLC

as Transmission Owner

and

Consumers Energy Company

as Local Distribution Company

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AMENDED AND RESTATED

DISTRIBUTION TRANSMISSION INTERCONNECTION AGREEMENT

This Amended and Restated Distribution Transmission Interconnection Agreement ("Agreement") is entered into by and between the Michigan Electric Transmission Company, LLC, a Michigan limited liability company ("Transmission Owner"), having a place of business at 27175 Energy Way, Novi, Michigan 48377, and Consumers Energy Company ("Local Distribution Company"), a Michigan company, doing business in Michigan and having a place of business at One Energy Plaza, Jackson, Michigan, 49201. Transmission Owner and Local Distribution Company are individually referred to herein as a "Party" and collectively as "Parties." This Agreement amends, restates and completely replaces any and all previous versions of the Distribution Transmission Interconnection Agreement between the Parties, and is effective as of _____.

WHEREAS, Transmission Owner requires access to parts of Local Distribution Company's assets, and Local Distribution Company requires access to parts of Transmission Owner's assets; and

WHEREAS, the Parties have agreed to execute this mutually acceptable Agreement in order to provide interconnection of the Local Distribution Company with the Transmission Owner and to define the continuing rights, responsibilities, and obligations of the Parties with respect to the use of certain of their own and the other Party's property, assets, and facilities.

NOW, THEREFORE, in consideration of their respective commitments set forth herein, and intending to be legally bound hereby, the Parties covenant and agree as follows:

ARTICLE 1. Definitions

Wherever used in this Agreement with initial capitalization, the following terms shall have the meanings specified or referred to in this Article 1.

1.1 Administrative Committee means the committee established pursuant to Article 6 of the Operating Agreement dated April 1, 2001, as amended and restated, between Local Distribution Company and Transmission Owner.

1.2 Agreement means this Interconnection Agreement between Local Distribution Company and Transmission Owner, including all attachments hereto, as the same may be amended, supplemented, or modified in accordance with its terms

1.3 Black Start Capability shall mean a generating unit that is capable of starting without an outside electrical supply.

1.4 Black Start Plan shall mean a plan utilizing Black Start Capability designed and implemented by the Transmission Owner in conjunction with its interconnected generation and distribution customers, Distribution System Control, other electric

systems, its Security Coordinator and ECAR, to energize portions of the Transmission System which are de-energized as a result of a widespread system disturbance.

1.5 Commission shall mean the Michigan Public Service Commission (MPSC), or its successor.

1.6 Confidential Information shall have the meaning set forth in Section 20.1 hereof.

1.7 Control Area shall mean an electric system, bounded by interconnection metering and telemetry. Generation within the Control Area is directed to operate in a manner prescribed by guidelines established by ECAR and NERC and in accordance with Good Utility Practice to (a) maintain scheduled interchange with other Control Areas, (b) maintain the operating frequency and (c) provide sufficient generating capacity to maintain operating reserves.

1.8 Distribution System shall mean, subject to and consistent with the provisions of Section 3.2 and 3.4 hereof, the equipment and facilities and the Interconnection Equipment owned, or that should be owned by the terms of this Agreement, by the Local Distribution Company and used to deliver power and energy to end users, including transformers, switches, and feeders rated at a Nominal Voltage of 138 kilovolts (kV) or less.

1.9 Distribution System Control shall mean the entity that has the ability and the obligation to operate the Distribution System Control Area to ensure that the aggregate electrical demand and energy requirements of the load is met at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements.

1.10 Distribution System Control Area shall mean a Control Area whose load and generation, and other bulk power supply points are integrated by the Transmission System.

1.11 Distribution System Control Center shall mean the electric Distribution System Control Center(s) that is/are responsible for monitoring and controlling the Distribution System in real time.

1.12 Distribution Transformer shall mean an electrical transformer which, generally, has its secondary low-side windings rated at Nominal Voltage of less than 138 kV.

1.13 Due Diligence shall mean the exercise of good faith efforts to perform a required act on a timely basis and in accordance with Good Utility Practice using the necessary technical and personnel resources.

1.14 ECAR is an acronym, which stands for the East Central Area Reliability coordination agreement. This is the Agreement under which Transmission Providers, who are signatories of the agreement, establish regional coordination

practices and guides to govern the electric coordinated operation and reliability of the East Central Region of North America. As used in this Agreement, the term ECAR includes any successor organization's reliability requirements.

1.15 Effective Date shall mean the closing date as defined in the Membership Interests Purchase Agreement between the Parties.

1.16 Eligible Customer shall have the same meaning as that term is defined under the Transmission Owner's OATT on file with the FERC.

1.17 Emergency means a condition or situation that in the reasonable good faith determination of the affected Party in accordance with Good Utility Practice contributes to an existing or imminent physical threat of danger to life or a significant threat to health, property or the environment.

1.18 Extended Outage shall mean an Unplanned Outage, in which facilities are automatically removed from service (typically by relay-action operating circuit breakers), with a duration of more than two (2) minutes.

1.19 FERC shall mean the Federal Energy Regulatory Commission or its successor federal agency.

1.20 Force Majeure shall have the meaning set forth under Article 16 hereof.

1.21 Forced Outage shall mean an Unplanned Outage, in which facilities are removed from service by operator intervention and not automatically such as by relay-action operating circuit breakers.

1.22 Good Utility Practice shall mean any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather includes all acceptable practices, methods, or acts generally accepted in the region.

1.23 Governmental Authority shall mean any foreign, federal, state, local or other governmental regulatory or administrative agency, court, commission, department, board, or other governmental subdivision, legislature, rulemaking board, tribunal, arbitrating body, or other governmental authority; provided such entity possesses valid jurisdictional authority to regulate the Parties and the terms and conditions of this Agreement.

1.24 ISO means Independent System Operator.

1.25 Interconnection Equipment shall mean all the equipment that is necessary for the interconnection of the Distribution System to the Transmission System which is located at the substations listed in Exhibit 1 hereto as it may be revised from time to time.

1.26 Interconnection Point(s) shall mean the point(s) at which the Distribution System is connected to the Transmission System, as set forth in Exhibit 1 hereto as it may be revised from time to time.

1.27 Interconnection Service shall mean the services provided by the Transmission Owner for the interconnection of the Distribution System with the Transmission System. Interconnection Service does not include the right to transmission service on the Transmission System, which service shall be obtained in accordance with the provisions of the Transmission Owner's OATT.

1.28 Interconnection Standards shall be those standards provided by the Transmission Owner to the Local Distribution Company to establish and maintain interconnection operation in compliance with standards of NERC, ECAR, applicable state or federal regulations or by mutual agreement of the Parties.

1.29 Interest Rate shall mean an annual percentage rate of interest equal to the lesser of (a) the prime rate published by the Wall Street Journal (which represents the base rate on corporate loans posted by at least 75% of the nation's banks) on the date due, plus 2%, or (b) the highest rate permitted by law.

1.30 Jointly Owned Assets shall mean those assets in which the Transmission Owner and Local Distribution Company have undivided ownership interests. Due to the nature of substation designs, many of the supporting substation assets (e.g., station batteries, fence, control houses, ground grid, yard stone, steel structures, and some protective relay equipment) cannot be separated by ownership and the Parties share in the ownership of such assets. The respective ownership of such assets by substation is shown in Exhibit 6.

1.31 Knowledge shall mean actual knowledge of the corporate officers or managers of the specified Person charged with responsibility for the particular function as of the Effective Date of this Agreement, or, with respect to any certificate delivered pursuant to the Agreement, the date of delivery of the certificate.

1.32 Least-Cost shall mean the lowest Transmission System and Distribution System facility costs, over the life of the facility, to accommodate an improvement need while adequately providing for reliability, operating, and maintenance requirements.

1.33 Reserved

1.34 Reserved

1.35 Local Distribution Company shall mean Consumers Energy Company and its successors and assigns.

1.36 Local Distribution Company Provided Services shall mean those services provided by the Local Distribution Company for the Transmission Owner by mutual agreement or contract.

1.37 Local Distribution Company's Representative shall be that person(s) identified as the point of contact for day-to-day operations of the Distribution System, identified in Section 2.3.

1.38 Momentary Outage shall mean a Distribution or Transmission System (in whole or in part) interruption in service with a duration of two (2) minutes or less.

1.39 Momentary Outage Event shall mean one or more Momentary Outages within any 60-minute period that are attributable to the same root cause.

1.40 NERC shall mean the North American Electric Reliability Council or its successor.

1.41 Network Security shall mean the ability of the Transmission System to withstand sudden disturbances such as unforeseen conditions, electric short circuits or unanticipated loss of system elements consistent with reliability principles used to design, plan, operate, and assess the actual or projected reliability of an electric system that are established by any Governmental Authority, NERC or ECAR and which are implemented by Transmission Owner or required of Transmission Owner in compliance with Security Coordinator directives.

1.42 Network Security Condition shall mean a condition or situation in which, in the reasonable good faith determination of Transmission Owner, Network Security is not satisfied or is threatened.

1.43 Nominal Voltage shall mean an accepted standard voltage level offered by the Transmission Owner, at various points on the Transmission System, including but not limited to 120 kV, 138 kV and 345 kV.

1.44 Normal System Condition shall mean any operating conditions of the Transmission System other than an Emergency or Network Security Condition.

1.45 Open Access Transmission Tariff or OATT shall mean the Open Access Transmission Tariff of the Transmission Owner on file with the FERC.

1.46 Operating Committee means the committee established pursuant to Section 6.4.3 of the Operating Agreement dated April 1, 2001, as amended and restated, between Local Distribution Company and Transmission Owner.

1.47 Party or Parties shall have the meaning set forth in the introductory paragraph of this Agreement.

1.48 Person shall mean any individual, partnership, limited liability company, joint venture, corporation, trust, unincorporated organization, or governmental entity or any department or agency thereof.

1.49 Planned Outage shall mean action by (i) Local Distribution Company or Transmission Owner to take its equipment, facilities or systems out of service, partially or completely, to perform work on specific components that is scheduled in advance and has a predetermined start date and duration pursuant to the procedures set forth in Sections 3.10.1, 3.10.2, and 3.10.4. Planned Outage shall not include the construction of new facilities or system elements, the modification of existing facilities or system elements addressed in Article 9, which includes, but is not limited to, activities associated with the construction of third party facilities or with the modifications required to accommodate third party facilities.

1.50 Planning Committee means the committee established pursuant to Section 6.4.3 of the Operating Agreement dated April 1, 2001, as amended and restated, between Local Distribution Company and Transmission Owner.

1.51 Protective Relay is a device which detects abnormal power system conditions and, in response, initiates automatic control action

1.52 Protective Relay System is a group of Protective Relays and associated sensing devices and communications equipment that detects system abnormalities and performs automatic control action to mitigate or reduce adverse effects of such abnormalities.

1.53 Qualified Personnel shall mean individuals trained for their positions in accordance with Good Utility Practice.

1.54 Radial Asset shall mean facilities used for the distribution of electric energy through a single circuit (which may consist of any number of wires or cables) running to a substation or substations to serve Local Distribution Company's load customers.

1.55 RTO means Regional Transmission Organization.

1.56 Regulated Substance means any contaminant, hazardous waste, hazardous substance, hazardous constituent, or toxic substance, as defined in the Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA), 42 USC 9601 et seq, Resource Conservation and Recovery Act (RCRA), 42 USC 6901 et seq, Toxic Substances Control Act (TSCA), 15 USC 2601 et seq, The Michigan Natural Resources and Environmental Protection Act (MCLA 324.101 et seq); or any other similar statutes now or hereafter in effect.

1.57 Release shall mean, spill, leak, discharge, dispose of, pump, pour, emit, empty, inject, leach, dump, or allow to escape into or through the environment.

1.58 Revenue Quality Metering System shall mean a system which includes current and voltage instrument transformers, secondary wiring, test switches, meter transducer(s), meter and loss compensation as set forth in Article 5.

1.59 RTU – Remote Terminal Units shall mean a device connected by a communication system to one or more master computers with appropriate software placed at various locations to collect data and perform remote control. It may also perform intelligent autonomous control of electrical systems and report the results back to the master computer(s).

1.60 Security Coordinator shall mean a NERC-approved entity that provides the security assessment and emergency operations coordination for one or more Control Areas or transmission owners and which has operational authority under NERC standards over the Transmission Owner.

1.61 Steady-State Voltage shall mean the value of a voltage after all transients have decayed to a negligible value. The root-mean-square value in the steady-state does not vary with time.

1.62 Supervisory Control and Data Acquisition (SCADA) shall mean a system that provides data acquisition, supervisory control and alarm display and control from remote field locations to control centers.

1.63 System Modification Impact shall mean a physical change to an electrical system, element or facility subject to this Agreement that would require the reclassification of the same from a Distribution System equipment, element or facility to a Transmission System equipment, element or facility, or vice versa, consistent with the facility ownership classifications provided for in Section 3.2 hereof, Good Utility Practice and applicable NERC standards.

1.64 Transmission Owner shall mean the Michigan Electric Transmission Company, LLC and its successors and assigns.

1.65 Transmission Owner's Representative(s) shall be that person(s) identified as the point for contact for day-to-day operations of the Transmission System, identified in Section 2.3.

1.66 Transmission System shall mean, subject to and consistent with the provisions of Section 3.2 and Section 3.4 hereof, any equipment and facilities for the delivery of energy across a network that are not part of the Distribution System and the equipment and facilities owned, or that should be owned by the terms of this Agreement, by the Transmission Owner for the delivery of energy across a network.

1.67 Transmission System Operations Center(s) shall mean the electric Transmission System control center(s) that is/are responsible for monitoring and controlling the Transmission System in real time.

1.68 Unplanned Outage shall mean action by Local Distribution Company or Transmission Owner to take its equipment, facilities or systems out of service, partially or completely, due to an unanticipated failure, when such removal from service was not scheduled in accordance with Sections 3.10.1, 3.10.2, and 3.10.4. Such removal from service may be automatic such as by relay-action operating circuit breakers or by operator intervention. Momentary interruptions are excluded from the definition of Unplanned Outages. Unplanned Outages include Forced Outages as well as Extended Outages.

ARTICLE 2. Operational Requirements

2.1 Subject to the terms and conditions of this Agreement, Transmission Owner shall provide Local Distribution Company Interconnection Service for each Interconnection Point identified in Exhibit 1, from the Effective Date for the term of this Agreement.

2.2 The Interconnection Points between the Transmission System and Distribution System are listed in Exhibit 1. It shall be the Transmission Owner's responsibility to annually prepare an addendum to this exhibit that shows all new or modified interconnections. The original Exhibit 1 and all addendums shall be retained for future reference.

2.3 Local Distribution Company's Representatives and Transmission Owner's Representatives are listed in Exhibit 2, as may be modified from time to time by either Party, giving written notice of changes regarding its Representative(s) to the other Party.

2.4 Interconnection Standards

2.4.1 The Interconnection Point(s) shall be established and maintained in accordance with Good Utility Practice and the applicable NERC, Federal, State, OATT and ECAR standards and policies for Transmission Owner service to Local Distribution Company.

2.4.2 Reactive Power. Transmission Owner and Local Distribution Company recognize and agree that they have a mutual responsibility for maintaining voltage at the Interconnection Points. Transmission Owner is responsible for maintaining Transmission System voltage as listed in Sections 8.1 and 8.2 and reasonably compensating for reactive power losses resulting from transmission service. The Local Distribution Company is responsible for controlling Distribution System voltage and compensating for Distribution System reactive power losses and reactive power consumed by retail customers. The Local Distribution Company may use a combination of static and dynamic reactive resources at various locations around the Transmission Owner's system. The Local Distribution Company's and the Transmission Owner's SCADA systems shall be used to determine the net exchange of reactive power on a total

interconnections basis. For those distribution substations where there are no SCADA facilities in place the reactive flows shall be determined from SCADA data on the connecting lines in conjunction with computer load flow simulations. At load levels below 90% of peak the system should be designed such that the average power factor for the sum of all Interconnection Points is between 90% lagging and 90% leading ("peak" as used here shall refer to a current year's maximum MW load for the Local Distribution Company). For load levels above 90% of peak the power factor should be at 98% (lagging or leading), or better. If the power factor falls below this minimum the Planning Committee shall review available options and determine the best method of addressing any resulting system problems.

2.5 (a) The Local Distribution Company shall comply with Transmission Owner's reasonable operating requirements or switching procedures. The Local Distribution Company shall verbally notify the Transmission Owner if the Local Distribution Company is unable to comply with this Section at any time during the term of the Agreement.

(b) The Transmission Owner shall comply with Local Distribution Company's reasonable operating requirements or switching procedures. The Transmission Owner shall verbally notify the Local Distribution Company if the Transmission Owner is unable to comply with this Section at any time during the term of the Agreement.

2.6 Local Distribution Company shall comply with the requests, orders, directives and requirements of Transmission Owner in its role of implementing the directives of the Security Coordinator. Any such requests, orders, directives or requirements of Transmission Owner must be (a) issued in accordance with Good Utility Practice, (b) not unduly discriminatory, (c) otherwise in accordance with applicable tariffs or applicable federal, state or local laws, (d) in conformance with NERC operating procedures, and (e) reasonably necessary to maintain the integrity of the Transmission System.

2.7 Load Shedding

2.7.1 Local Distribution Company shall comply, as part of a Control Area program, with installation of automatic underfrequency load shedding equipment and maintain compliance with the standards set forth in NERC and ECAR operating standards and policies at Transmission Owner's expense.

2.7.2 The Transmission Owner may direct the Local Distribution Company to shed load to maintain the reliability and integrity of the Transmission System, in accordance with the OATT. The Transmission Owner and the Local Distribution Company will comply with MPSC directives and will

endeavor to minimize the impact on the Local Distribution Company customers.

2.8 Not a Reservation for Transmission Service

2.8.1 Local Distribution Company, or an Eligible Customer under the OATT, shall be responsible for making arrangements under the OATT for transmission and any ancillary services associated with the delivery of capacity and/or energy purchased or produced by the Local Distribution Company, which services shall not be provided under this Agreement.

2.8.2 Local Distribution Company and Transmission Owner make no guarantees to the other under this Agreement with respect to transmission service that is available under the Transmission Owner's OATT or any other tariff under which transmission service may be available in the region. Nothing in this Agreement shall constitute an express or implied representation or warranty with respect to the current or future availability of transmission service. Should the Parties enter into an arrangement under the OATT or another tariff, any terms in this Interconnection Agreement that may be in conflict with that tariff shall be subordinate to the terms of that tariff.

ARTICLE 3. Ownership, Conveyance, Operation and Maintenance

3.1 The Operating Committee shall develop specific methods and procedures with respect to Local Distribution Company's and Transmission Owner's systems covering at least, but not limited to, the following areas: safety, voltage control, outage planning and implementation, service restoration, emergency operations procedures, frequency controls, environmental matters, and maintenance planning and execution.

3.2 Facility Classification and Rights

3.2.1 Facility Classifications

3.2.1.1 As between the Parties, Local Distribution Company shall be the exclusive owner, operator and constructor of Distribution System equipment, elements, and facilities, and shall have the exclusive right to build, own, operate, and maintain: (i) all equipment, elements, and facilities operated below a Nominal Voltage of 120 kV; and (ii) all new Radial Assets operated at a Nominal Voltage at or above 120 kV.

3.2.1.2 As between the Parties, Transmission Owner is and shall be the exclusive owner, operator, and constructor of Transmission System equipment, elements and facilities.

3.2.1.3 As contemplated in Section 3.4.2, a System Modification Impact will require the reclassification of a facility. Either Party may identify a physical change to the electrical functioning of any equipment, element or facility subject to this Agreement that would require the reclassification of the same from a Distribution System equipment, element or facility to a Transmission System equipment, element or facility, or vice versa, consistent with the facility ownership classifications provided for in this Section 3.2, Good Utility Practice, and applicable NERC standards. Such identification shall be made via written notice to the other Party. The conveyance of the identified equipment, element or facility shall be accomplished under the procedures identified in Section 3.4. If the other Party disputes the applicability of reclassification of a particular equipment, element or facility, then the dispute resolution procedures in Article 25 shall apply.

3.2.2 Recordkeeping

3.2.2.1 Exhibit 5 has been omitted from this Agreement. Previously, this Exhibit reflected ownership changes and the Parties agree this Exhibit is unnecessary.

3.2.2.2 Wiring Diagrams (WDs) will be updated continuously in each Party's Drawing Management System (DMS) which is shared between the Parties and approved by both Parties at least annually when Exhibit 6 is updated to show changes in ownership. For purpose of this Section 3.12, such submission and approval of changes shall be in writing consistent with Section 11.1.

3.3 All operation and maintenance activities will be the financial responsibility of the owning Party. All operation and maintenance activities on Jointly Owned Assets will be under the direction and control of the Party that owns the greater percentage of the major equipment at that location. In the case where both Parties own an equal share the Local Distribution Company shall have such direction and control. The Parties' respective share of responsibility for the costs of all operation and maintenance activities on Jointly Owned Assets shall be the same percentage as the percentage of major equipment owned by the Party in that substation as set forth in Exhibit 6 and its subsequent addendums, provided that the minority owner's ownership interest exceeds 1%; if it does not, then the majority owner will be solely responsible for these operation and maintenance costs and corresponding capital replacements. All generation-related assets owned by the Local Distribution Company in a substation will be included as a part of the Local Distribution Company's assets in making this calculation. Responsibilities related to third-party owned generation-related assets will be split according to the nominal operating voltage at the point of connection of the generation circuit. At 120 kV and above the third-party generation-related assets

will be included as a part of the Transmission Owner's assets for purposes of making this calculation. Below 120 kV the third-party generation-related assets will be included as a part of the Local Distribution Company's assets for purposes of making this calculation. Major equipment shall be defined as main power transformers, 23 kV, 46 kV, 138 kV, and 345 kV circuit breakers, power system regulators and reclosers, and 46 kV and 138 kV capacitor banks. (Any three-phase installation of such equipment shall count as a single unit). Exhibit 6 will be updated with an addendum at least annually by the Transmission Owner and approved in writing by the Local Distribution Company to show all changes in equipment ownership in the joint substations. The original Exhibit 6 and all addendums will be retained for future reference. In those substations where each Party owns assets each Party shall be financially responsible for its appropriate share of station power energy usage.

3.4 Reclassification and Conveyance

3.4.1 The facility classifications provided for in Subsection 3.2.1 hereof shall govern the Parties' ownership of existing and future Distribution System facilities and Transmission System facilities, except as provided in Subsection 3.4.2.

3.4.2 Any System Modification Impact shall require a Party to convey ownership to the appropriate Party in accordance with the ownership classifications provided for in Section 3.2 and the terms of this Section 3.4. However, no such reclassification shall affect how the other Sections of this Agreement are applied until there is a change in ownership of the facilities involved and until any related changes are made to this Agreement and its exhibits, as may be required. Upon such a change in ownership, the Planning Committee shall revise any Exhibits hereto when needed to reflect the change in ownership.

3.4.3 A facility conveyed pursuant to Section 3.4.2 shall be priced at 1.18 times the seller's net plant value but in any case, shall not be less than zero dollars (i.e., no payment from seller to purchaser will occur as a result of net plant value being less than zero). As used herein, "net plant value" shall mean the asset's original cost depreciated according to the seller's accepted accounting method. In addition, should either Party plan to abandon or otherwise take out of service any facilities which could be of use as part of the other Party's system, it shall offer to convey to the other Party such facilities before they are taken out of service under the same pricing formula outlined above.

3.4.4 All types of conveyances discussed in this Section 3.4 shall be subject to the following conditions:

(a) The Planning Committee shall within 12 months of the Effective Date of this Agreement develop appropriate timeframes and procedures for

accomplishing such conveyances. For the avoidance of doubt, any previous agreements, understandings, or practices between the Parties on this subject matter that in any way conflict with the terms of this Agreement, including but not limited to anything stated in Planning Practice 6, are hereby abrogated and superseded by this Agreement.

(b) At least 12 months (or as close as feasible to 12 months) before implementing system modifications which would result in such a conveyance, the Party planning to do such modifications shall notify the other Party of such plans. The other Party, if it wishes, shall then have 2 months within which to propose an alternative modification which is consistent with Good Utility Practice, which would reduce or eliminate the need for conveyances, and which would cost the Party seeking to do the modifications no more than the originally proposed modification. If such an alternative is provided in a timely manner, the Party proposing to do the modification shall consider the alternative and shall not unreasonably refuse to pursue the alternative instead of the original proposal.

(c) Possible impediments to timely conveying the property in question (e.g., difficulty in getting release from the conveyor's indenture) shall be referred to the Administrative Committee. The Administrative Committee is authorized to modify the requirements of this Section with regard to such a specific proposed modification however it deems appropriate in light of the possible impediment and other circumstances.

3.5 Each Party shall operate any equipment that might reasonably be expected to have impact on the operations of the other Party in a safe and efficient manner and in accordance with all applicable federal, state, and local laws, NERC operating practices, and Good Utility Practice, and otherwise in accordance with the terms of this Agreement. Each Party shall comply with the reasonable requests, orders, directives and requirements of the other Party, which are authorized under this Agreement.

3.6 (a) Without limiting the generality of Section 3.5, Local Distribution Company shall own, operate, and maintain its Distribution System in a manner in accordance with Good Utility Practice to prevent degradation of voltage or services of the Transmission System. The Local Distribution Company shall be responsible for the costs to repair or replace the Distribution System and Local Distribution Company's Interconnection Equipment.

(b) Without limiting the generality of Section 3.5, Transmission Owner shall own, operate, and maintain its Transmission System in a manner in accordance with Good Utility Practice to prevent degradation of voltage or services of Local Distribution Company's Distribution System. The Transmission Owner shall be responsible for the costs to repair or replace the Transmission System and Transmission Owner's Interconnection Equipment.

(c) Without limiting the generality of Section 3.5, Local Distribution Company or Transmission Owner, as appropriate pursuant to Section 3.3 hereof, shall operate and maintain Jointly Owned Assets in a manner in accordance with Good Utility Practice to prevent degradation of voltage or services to either Party.

3.7 (a) Except during an Emergency, Local Distribution Company shall not, without prior Transmission Owner authorization, operate any Transmission Owner circuit, including transformer, line, or bus elements. Local Distribution Company shall retain the right to operate Transmission Owner equipment during an Emergency. When practical, prior to operation of such equipment, Local Distribution Company shall provide notice to the Transmission Owner. The Local Distribution Company shall also have the right to operate Transmission Owner substations that serve five or fewer customers to maintain the integrity of the Distribution System under the specific real time direction of the Transmission Owner. The Local Distribution Company shall not operate any Transmission System circuit if upon notice the Transmission Owner expressly refuses to grant permission to the Local Distribution Company. Within five (5) working days of such Emergency, Local Distribution Company shall provide written explanation of such Emergency to Transmission Owner.

(b) Except during an Emergency, Transmission Owner shall not, without prior Local Distribution Company authorization, operate any Local Distribution Company circuit, including transformer, line, or bus elements. Transmission Owner shall retain the right to operate Local Distribution Company equipment, during an Emergency for imminent personnel safety threat, to prevent damage to equipment or to maintain the integrity of the Transmission System. When practical, prior to operation of such equipment, Transmission Owner shall provide notice to Local Distribution Company. Transmission Owner shall not operate any Distribution System circuit if upon notice the Local Distribution Company expressly refuses to grant permission to the Transmission Owner. Within five (5) working days of such Emergency, Transmission Owner shall provide written explanation of such Emergency to Local Distribution Company.

(c) In an Emergency, joint facilities shall be operated by the Party able to first respond with Qualified Personnel.

3.8 Local Distribution Company and Transmission Owner shall design, install, test, calibrate, set, and maintain their respective Protective Relay equipment in accordance with Good Utility Practice, applicable federal, state, or local laws and this Agreement, as set forth in Article 6 hereof. In the case of jointly owned relaying equipment, the Party having direction and control pursuant to Section 3.3 hereof shall design, install, calibrate, set, and maintain Protective Relay equipment in accordance with Good Utility Practice. Without limiting the generality of Section 3.6(c) above, costs for such work will be split between the

Companies on a predetermined ownership percentage basis as set forth in the then-current version of Exhibit 6, provided that the minority owner's ownership interest exceeds 1%; if it does not, then the majority owner will be solely responsible for these costs.

3.9 (a) If Transmission Owner reasonably determines that (i) any of Local Distribution Company's Interconnection Equipment fails to perform in a manner in accordance with Good Utility Practice or this Agreement, or (ii) Local Distribution Company has failed to perform proper testing or maintenance of its Interconnection Equipment in accordance with Good Utility Practice or this Agreement, Transmission Owner shall give Local Distribution Company written notice to take corrective action. Such written notice shall be provided by Transmission Owner to Local Distribution Company's Representative as soon as practicable upon such determination. If Local Distribution Company fails to initiate corrective action promptly, and in no event later than seven (7) days after the delivery of such notification, and if in Transmission Owner's reasonable judgment leaving Local Distribution Company's Distribution System connected with Transmission System would create an Emergency or Network Security Condition, Transmission Owner may, with as much prior verbal notification to Local Distribution Company and Distribution System Control as practicable, open only the Interconnection Point(s) needing corrective action connecting the Local Distribution Company and Transmission Owner until appropriate corrective actions have been completed by Local Distribution Company, as verified by Transmission Owner. Prior to taking such action, Transmission Owner shall give appropriate consideration to the needs of the Local Distribution Company's end-use customers. Transmission Owner's judgment with regard to an interruption of service under this paragraph shall be made in accordance with Good Utility Practice and subject to Section 3.1 hereto. In the case of such interruption, Transmission Owner shall immediately confer with Local Distribution Company regarding the conditions causing such interruption and its recommendation concerning timely correction thereof. Both Parties shall act promptly to correct the condition leading to such interruption and to restore the connection.

(b) If Local Distribution Company reasonably determines that (i) any of Transmission Owner's Interconnection Equipment fails to perform in a manner in accordance with Good Utility Practice or this Agreement, or (ii) Transmission Owner has failed to perform proper testing or maintenance of its Interconnection Equipment in accordance with Good Utility Practice or this Agreement, Local Distribution Company shall give Transmission Owner written notice to take corrective action. Such written notice shall be provided by Local Distribution Company to Transmission Owner's Representative as soon as practicable upon such determination. If Transmission Owner fails to initiate corrective action promptly, and in no event later than seven (7) days after the delivery of such notification, and if in Local Distribution Company's reasonable judgment leaving Transmission System connected with Local

Distribution Company's Distribution System would create an Emergency, Local Distribution Company may, with as much prior verbal notification to Transmission Owner and Distribution System Control as practicable, open only the Interconnection Point(s) needing corrective action connecting the Transmission Owner and Local Distribution Company until appropriate corrective actions have been completed by Transmission Owner, as verified by Local Distribution Company. Local Distribution Company's judgment with regard to an interruption of service under this paragraph shall be made in accordance with Good Utility Practice and subject to Section 3.1 hereto. In the case of such interruption, Local Distribution Company shall immediately confer with Transmission Owner regarding the conditions causing such interruption and its recommendation concerning timely correction thereof. Both Parties shall act promptly to correct the condition leading to such interruption and to restore the connection.

3.10 Outages

3.10.1 Outage Authority and Coordination. In accordance with Good Utility Practice, each Party may, in close cooperation with the other, remove from service its system elements that may impact the other Party's system as necessary to perform maintenance or testing or to replace installed equipment. Absent the existence of an Emergency, the Party scheduling a removal of a system element from service will schedule such removal on a date mutually acceptable to both Parties, in accordance with Good Utility Practice.

3.10.2 The Parties shall coordinate inspections, Planned Outages, and maintenance of their respective equipment, facilities and systems so as to minimize the impact on the availability, reliability and security of both Parties' systems and operations when the outage is likely to have a materially adverse impact on the other Party's system or the Local Distribution Company's end-use customers. Subject to the confidentiality provisions of Article 20, on or before October 1 of each year during the term hereof, the Parties shall exchange non-binding Planned Outage schedules for the following calendar year, which shall be developed and followed in accordance with Good Utility Practice, for the Distribution System and Transmission System. The Parties shall communicate the outage schedules as promptly as possible, provided that in no event shall such schedule be provided less than fifteen (15) days prior to a Planned Outage. The Parties shall keep each other updated regarding any changes to such schedules.

3.10.3 Unplanned Outages

3.10.3.1 Distribution System Unplanned Outage. In the event of an Unplanned Outage of a system element of the Distribution System adversely affecting the Transmission System, the Local

Distribution Company will act in accordance with Good Utility Practice to promptly restore that system element to service unless the Local Distribution Company obtains concurrence from the Transmission Owner that some deferral is reasonable, and this concurrence shall not be unreasonably withheld. The Local Distribution Company shall plan and maintain its Distribution System such that the average length of distribution system outages having a direct impact on the Transmission System shall not exceed 166 minutes per event on an annual basis. For any year in which the average outage duration exceeds this limit, the Local Distribution Company shall develop a plan to improve the outage restoration process and reduce outages and shall obtain the Transmission Owner's concurrence with this plan. Within forty-eight hours (48) of the beginning of any Unplanned Outage, the Local Distribution Company shall provide the Transmission Owner with a restoration plan.

3.10.3.2 Transmission System Unplanned Outage. In the event of an Unplanned Outage of a system element of the Transmission System adversely affecting the Local Distribution Company's Distribution System, the Transmission Owner will restore the system to normal as soon as possible unless the Transmission Owner obtains concurrence from the Local Distribution Owner that some deferral is reasonable, and this concurrence shall not be unreasonably withheld. The Transmission Owner shall plan and maintain its Transmission System such that the average length of Transmission System outages having a direct impact on customers of the Local Distribution Company shall not exceed 166 minutes on an annual basis. For any year in which the average outage duration exceeds this limit, the Transmission Owner shall develop a plan to improve the outage restoration process and reduce outages and shall obtain the Local Distribution Company's concurrence with this plan. Within forty-eight hours (48) of the beginning of any Unplanned Outage the Transmission Owner shall provide the Local Distribution Company with a restoration plan. For any 138 kV system outage it is expected that the system will be restored to its normal configuration within seven (7) days; for any 345 kV system outage it is expected that the system will be restored to its normal configuration within thirty (30) days. If it is expected that any Unplanned Outage will exceed these limits the Transmission Owner shall provide the Local Distribution Company with detailed information on measures being taken to minimize the outage time.

3.10.4 Planned Outages

3.10.4.1 Distribution System Planned Outage. In the event of a Planned Outage of a system element of the Distribution System adversely affecting the Transmission System, the Local Distribution Company will act in accordance with Good Utility Practice to promptly restore that system element to service in accordance with its schedule for the work that necessitated the Planned Outage.

3.10.4.2 Transmission System Planned Outage. The Transmission Owner shall review all Transmission System Planned Outages with the Local Distribution Company. In the event of a Planned Outage of a system element of the Transmission System adversely affecting the Local Distribution Company's Distribution System, the Transmission Owner will act in accordance with Good Utility Practice to promptly restore that system element to service in accordance with its schedule for the work that necessitated the Planned Outage.

3.11 The Parties shall use best efforts in accordance with Good Utility Practice to coordinate operations in the event of any Forced or Planned Outage that affects the other Party's system.

3.12 Black Start Plan Participation. In accordance with Good Utility Practice, Local Distribution Company agrees to participate in Transmission Owner's Black Start Plan for the Distribution System and the Transmission System, as well as any verification testing.

3.13 The Parties shall notify and make available in a timely manner, electric system modeling information necessary for the other Party to monitor, analyze, and protect its facilities in a real time environment, no less than 30 days prior to the energization of new or reconfigured network facilities.

ARTICLE 4. Supervisory Control and Data Acquisition, SCADA

4.1 If the Transmission Owner chooses to operate its own SCADA system, or to make modifications or additions to the existing system, the following terms and conditions of this Article 4 will apply.

4.2 Interconnection Points containing SCADA and communications equipment installed prior to April 1, 2001, shall be considered to satisfy the terms and conditions of this article. For those Interconnection Points that existed prior to April 1, 2001 that did not contain SCADA and communications equipment, and for new Interconnection Points installed after April 1, 2001 where SCADA and communications equipment is necessary for and requested by the Transmission Owner to perform monitoring, state estimation and contingency analysis, the Local Distribution Company shall install and operate such equipment at the

Transmission Owner's expense. Each Interconnection Point or other mutually agreeable location with SCADA and communications equipment shall have one dedicated communications path to the Local Distribution Company's control center for the RTU data. The cost of the dedicated communications path and general use station phone shall be shared on an equal basis. Additional data paths, SCADA equipment, and communications equipment requested, either emanating from the substation, the Local Distribution Company's control center, or the Transmission Owner's control center, will be at the expense of the requestor. This data and status information may be real time or with a time delay mutually acceptable to the Parties. The method of providing this data and control will be via an industry standard protocol such as Inter-Control Center Protocol (ICCP) or other method agreed to by the Parties. Such data may include, but not be limited to megawatts, megavars, voltage, amperes, device status, interchange schedule error, and communication system status.

4.3 The Transmission Owner reserves the right at its expense, to require, for new, or modified Local Distribution Company Interconnection Points, installation of a Transmission Owner's RTU or installation of a dual port RTU to provide data and control directly to the Transmission Owner within the Local Distribution Company's substation. The Local Distribution Company will assist in furnishing desired inputs for the Transmission Owner's RTU.

4.4 The operating metering system shall consist of instantaneous values of MW, MVAR, and voltage.

4.4.1 Values shall be inputted to a RTU or comparable communication device for communication with the Party having Control Area responsibility.

4.4.2 Transducers may utilize the voltage transformers and current transformer secondary circuits also utilized by the revenue metering equipment for a particular interconnection. In such case, the performance criteria listed in Exhibit 4 of the Agreement, Metering Specifications, for the voltage transformers and the current transformers, shall apply. Relaying class voltage transformers and or current transformers shall not be utilized unless mutually agreed between all the owners of the metering equipment and the Local Distribution Company.

4.4.3 Transducers shall have maximum 0.3% inaccuracy. Transducers shall be field calibrated as necessary but at least once every ten (10) years and documentation shall be retained showing the calibration results until next calibration.

4.4.4 Telemetry shall be maintained and calibrated such that overall inaccuracy of MW, MVAR, and voltage values is less than 1.0% of full scale.

4.5 To the extent new RTUs and associated communications equipment is to be installed, the Local Distribution Company shall install or facilitate installation of

the RTU and associated communications equipment as soon as practicable, provided that installation shall be accomplished within a time period of no more than 270 days following notice by Transmission Owner or prior to commissioning of any new Interconnection Points.

ARTICLE 5. Revenue Metering

5.1 Transmission Owner shall own, operate, test and maintain any metering equipment at the Interconnection Points, as required by this Article 5 not including any metering equipment owned by the Local Distribution Company for use in metering its end-use customers. Transmission Owner and Local Distribution Company agree that, as to all Interconnection Points in existence as of the Effective Date, no new or different metering equipment or arrangements shall be required. For existing Interconnection Points where low-side metering exists without loss compensation, the Parties will agree to adjust the metering data in such a manner to account for any real power losses between the location of the meter and the Interconnection Point. To the extent existing metering equipment is replaced and when new metering equipment is installed at Interconnection Points in existence as of the Effective Date, such replacements or installations shall meet the standards set in Section 5.2. Transmission Owner shall provide, install, own, operate, test, and maintain the new metering equipment located at the Interconnection Points.

5.2 The Revenue Quality Metering System shall consist of all instrument transformers (current and voltage), secondary wiring, test switches, and meter(s) required to determine the metering values for record for any given metering point

5.2.1 Metering shall be form 9, 3-element for 4-wire systems and form 5, 2-element for 3-wire systems.

5.2.2 Meters shall measure, at a minimum, megawatt hours and megavar hours and have bi-directional capability, where applicable. All measured values shall have individual outputs where applicable and a minimum 35-day interval data recording capability for each measured value.

5.2.3 Whenever feasible, any new metering facilities shall be located at the same physical location as the Interconnection Point. If it is not reasonable to have the metering facilities and the Interconnection Point at the same physical location, the metering data will be adjusted to account for real power losses between the location of the meter and the Interconnection Point.

5.2.4 Transmission Owner shall maintain records that demonstrate compliance with all meter tests and maintenance conducted in accordance with Good Utility Practice for the life of the Interconnection Point. Local Distribution Company shall have reasonable access to the records.

5.2.5 For installations where the metering is performed using loss compensation, the factory certified test results of the power transformer, if available, including load, no-load losses and calculated meter loss calculations, shall be recorded in a written record. Local Distribution Company shall have reasonable access to the records.

5.2.6 Transmission Owner shall maintain records of the factory certified test results, or the utility test shop test results, showing compliance of the meters with the applicable metering test standards.

5.2.7 Transmission Owner's Metering equipment shall be tested by Transmission Owner at its own expense not less than once every year, unless an extension of the testing cycle is agreed upon by the Parties. The accuracy of such metering equipment shall be maintained by Transmission Owner in accordance with applicable regulatory standards. At the request of either Party, special tests shall be made. If any special meter test discloses the metering device to be registering within acceptable limits of accuracy as specified herein, then the Party requesting such special meter test shall bear the expense thereof. Otherwise, the expense of such test shall be borne by the owner. Representatives of either Party shall be afforded opportunity to be present at all routine or special tests and upon occasions when any readings for purposes of settlements hereunder are taken from meters not producing an automatic record.

5.2.8 If, as a result of any test, any meter shall be found to be registering more than two (2) percent above or below one hundred (100) percent of accuracy, the account between the Parties hereto shall be corrected for a period equal to one-half of the elapsed time since the last prior test, according to the percentage of inaccuracy so found, except that if the meter shall have become defective or inaccurate at a reasonably ascertainable time since the last prior test of such meter, the correction shall extend back to such time. No meter shall be left in service if found to be more than two (2) percent above or below one hundred (100) percent of accuracy. Should metering equipment at any time fail to register, the energy delivered shall be determined from the best available data. All meters shall be kept under seal, such seals to be broken only when the meters are to be tested or adjusted.

5.2.9 Test switches shall be installed to allow independent testing and/or replacement of each meter and transducer utilizing the secondary circuit so as not to interrupt the operation of other devices utilizing the secondary circuit.

5.2.10 In substations where an RTU or other remote data collecting and telecommunication device is present, meters shall have form C, 3-wire

outputs with programmable values determined by the Transmission Owner for bi-directional MWHs and MVARs.

5.2.11 In the event an interconnection meter needs replacement or repair, a representative from Local Distribution Company shall be given a reasonable opportunity to be present during such repair or replacement.

ARTICLE 6. Protective Relaying and Control

6.1 Transmission Owner and the Local Distribution Company shall, in accordance with Good Utility Practice, coordinate, review and approve all new Protective Relaying equipment, including equipment settings, Protective Relay schemes, drawings, and functionality associated with each Interconnection Point. Protective Relaying equipment and schemes installed before the date of this agreement shall be considered to satisfy the terms and conditions of this Article 6. When existing equipment or schemes are replaced or when new equipment or schemes are installed per this Article 6 or in association with new Interconnection Points, then the terms and conditions of Article 6 shall apply. Each Party shall incur the expense for the work on its system.

6.2 To the extent that there is generation on the Distribution System which, in the reasonable judgment of either Party, may contribute material amounts of current to a fault on the Transmission System, the Local Distribution Company shall have and enforce standards to ensure the provision, installation and maintenance of relays, circuit breakers, and all other devices necessary to promptly remove any fault contribution of such generation to any short circuit occurring on the Transmission System and not otherwise isolated by the Transmission Owner equipment. Such standards will be included in the Local Distribution Company's connection requirements for generation. Transmission Owner and Local Distribution Company shall not be responsible for protection of such generation.

6.3 Transmission Owner shall own, operate, maintain and test those Protective Relay Systems that control their breakers or equivalent protective devices. Local Distribution Company shall own, operate, maintain, and test those Protective Relay Systems that control their breakers or equivalent protective devices governed by this Article 6. The Parties shall maintain, and, as necessary, upgrade their respective Protective Relay Systems and shall provide the other Party with access to available copies of operation and maintenance manuals and test records for all relay equipment upon request. The Transmission Owner will provide protective relay settings for the relays that control breakers or equivalent protective devices owned by the Local Distribution Company that also protect Transmission Owner's equipment. The Local Distribution Company will review and apply the settings.

6.4 The owner (Transmission Owner or Local Distribution Company) of the line will provide the relay communication channel necessary for line protection at its

expense. Owner will participate with other Party to test communication schemes upon request without charge.

6.5 The Parties shall test their respective relays associated with the Interconnection Points for correct calibration and operation. Parties shall coordinate design, installation, operation, and testing of Protective Relay schemes to insure that such relays operate in a coordinated manner so as to not cause adverse operating conditions on the other Party's system.

6.6 Local Distribution Company shall be responsible for Protective Relay maintenance, calibration and functional testing of relay systems that protect Local Distribution Company's equipment associated with the Interconnection Points and that protect Transmission Owner from Local Distribution Company's Interconnection Equipment to the extent such calibration and testing are in accordance with Good Utility Practice. All such maintenance and testing must be performed by Qualified Personnel selected by the Local Distribution Company. In addition, Local Distribution Company shall allow Transmission Owner to conduct visual inspection of all Protective Relays and associated maintenance records directly related to the interconnection. Related maintenance and operational records shall be maintained by the Local Distribution Company in accordance with Good Utility Practice. Upon completion of Protective Relay calibration testing and relay functional testing, Local Distribution Company shall make available copies of test reports and related records for review by Transmission Owner upon request. Local Distribution Company shall review test reports and document that Protective Relay System's tests and settings, as shown on such test reports, have been done in accordance with the equipment's specifications and Good Utility Practice.

6.7 (a) As Transmission Owner's system protection requirements change, Transmission Owner will upgrade its Protective Relaying System in accordance with Good Utility Practice. If these upgrades affect the serviceability and acceptability of the Protective Relaying Systems on the Interconnection Equipment which may be installed, owned, and operated by Local Distribution Company, the Local Distribution Company must upgrade its Protective Relay Systems at its expense (unless such modifications are required in association with the addition of generation to the system in which case Section 9.8 shall apply) as necessary to bring them into compatibility with that installed by Transmission Owner. Transmission Owner shall give Local Distribution Company notice of such upgrade as soon as practicable prior to the anticipated date of such upgrade. Any proposed protective system upgrades shall be reviewed by the Planning Committee in accordance with Section 7.3(vi) hereof.

(b) As Local Distribution Company's system protection requirements change, Local Distribution Company will upgrade its Protective Relaying System in accordance with Good Utility Practice. If these upgrades affect the serviceability and acceptability of the Protective Relaying Systems on the Interconnection Equipment which may be installed, owned, and operated by Transmission Owner,

Transmission Owner must upgrade its Protective Relaying Systems at its expense (unless such modifications are required in association with the addition of generation to the system in which case Section 9.8 shall apply) as necessary to bring them into compatibility with that installed by Local Distribution Company. Local Distribution Company shall give Transmission Owner notice of such upgrade as soon as practicable prior to the anticipated date of such upgrade. Any proposed protective system upgrades shall be reviewed by the Planning Committee in accordance with Section 7.3(vi) hereof.

6.8 Local Distribution Company shall provide necessary space to install or expand relay panels for substation system protection if requested by Transmission Owner. Any incremental costs required to accommodate such request shall be the responsibility of the Transmission Owner.

6.9 Transmission Owner shall provide the necessary space to install or expand relay panels for substation system protection if requested by Local Distribution Company. Any incremental costs required to accommodate such request shall be the responsibility of the Local Distribution Company.

6.10 Each Party will provide fault recorder, sequence of events, and relay information to the other party as needed and in a reasonable amount of time.

ARTICLE 7. Planning and Obligation to Serve

7.1 Adequacy Obligation. Subject to applicable regulatory approvals, including adherence to Least-Cost planning requirements and principles, adherence to applicable NERC, ECAR or other regional reliability council or successor organization's reliability requirements, and all other applicable operating reliability criteria and subject to the oversight and direction of the appropriate RTO or ISO, the Transmission Owner shall operate, maintain, plan and construct its Transmission System in accordance with Good Utility Practice in order to:

(i) deliver on a reliable basis the projected capacity and energy needs of all loads served by the Local Distribution Company's Distribution System and dependent upon the Transmission Owner's facilities for delivery of such energy to the Distribution System;

(ii) provide needed support to the Local Distribution Company where a transmission addition is the Least-Cost electric solution to an improvement need, including but not limited to, the reliability needs of the Local Distribution Company; and

(iii) deliver energy from both existing and new generating facilities connected to and dependent upon Transmission Owner's transmission of such energy

7.2 With regard to planning and construction of projects which affect Local Distribution Company and Local Distribution Company's load-serving area, the

Parties shall develop methods and procedures covering at least the following areas:

(i) coordination between short-term and long-term distribution and transmission planning;

(ii) developing and sharing computer simulation models needed to support Transmission Owner and Local Distribution Company planning activities;

(iii) coordination of permitting (including local and state approvals) and siting;

(iv) engineering and scheduling of new projects;

(v) construction and inspection standards;

(vi) information-sharing and priority-setting; and

(vii) health and safety issues.

7.3 With respect to Local Distribution Company's load-serving area, the Planning Committee, shall:

(i) implement the methods and procedures developed pursuant to Section 7.2;

(ii) review planning studies and reports regarding projects needed or proposed for the area in the next five (5) years, or as determined by the Planning Committee;

(iii) recommend additional studies or evaluation of plans;

(iv) follow Least-Cost planning principles in recommending specific projects;

(v) at least once every year, prepare a planning report which shall include in priority order a list of projects proposed by either Party for the next year, the estimated costs of such projects, and the timetable for such projects, including the in-service date; and

(vi) review proposed programmatic changes to the electric system, including protective system upgrades.

7.4 If the Parties agree upon the need for any such project, they shall cooperate and coordinate in seeking all necessary regulatory approvals for such project. Transmission Owner shall coordinate and cooperate with Local Distribution

Company with respect to all communications and commitments to municipal, county, and state agencies involved in such project.

7.5 If Local Distribution Company proposes construction of a transmission project and Transmission Owner does not agree that such project is needed, Local Distribution Company shall have the right to petition an appropriate RTO, ISO or applicable regulatory agency for a declaratory ruling on whether the proposed project is needed pursuant to Transmission Owner's public-utility duty to plan and construct a reliable, adequate Transmission System.

7.6 Load Growth and Reliability Needs. Transmission Owner is obligated to plan and install any Transmission System components that may be necessary, as determined by a Least-Cost planning process in accordance with Section 7.1 and consistent with the established and consistently applied reliability criteria of the Parties, to accommodate Local Distribution Company's planned load growth and planned reliability improvements. Transmission Owner will construct new interconnections to Local Distribution Company facilities in accordance with Transmission Owner's planning criteria, other agreements in effect between the Parties, and Good Utility Practice. Transmission Owner shall bear the responsibility for such planning and installing in accordance with this Article 7. Transmission Owner's obligations under this Section 7.6 shall include the planning and installation of any new Interconnection Points that may be necessary to accommodate Local Distribution Company's planned load growth and planned reliability improvements. Recovery of the cost of such additions shall be in accordance with the OATT or other applicable tariff.

7.7 Local Distribution Company shall be the first point of contact and the wire-services provider for end-use customers.

7.8 Transmission Owner shall annually submit to Local Distribution Company, no later than February 1 of each year:

(i) Transmission Owner's plans covering the next five (5) years, or as determined by the Planning Committee, for installing Transmission System components that may be necessary to accommodate Local Distribution Company's planned load growth and reliability improvements as described in Section 7.6. Transmission Owner's plans shall include, but not be limited to, cost estimates and installation schedules for Transmission System components, and shall provide specific detail sufficient to allow Local Distribution Company to compare Transmission Owner's plans with Local Distribution Company's in-service requirements to meet its planned load growth and reliability needs.

(ii) A description of any changes to the Local Distribution Company's Distribution System that may be needed to accommodate

Transmission Owner's plans set forth in Section 7.8(i) will be requested by the Transmission Owner.

(iii) Projected voltage levels under Normal System Conditions and Transmission Owner's FERC 715 Planning criteria conditions at anticipated annual peak load and 80% of anticipated annual peak load for each Interconnection Point with planned additions for the next five (5) years, or as determined by the Planning Committee.

7.9 Local Distribution Company shall annually submit to Transmission Owner:

(a) no later than December 1 of each year, the most recent actual summer and winter demands in megawatts (MW) and megavars (MVAR) for all Interconnection Points connected to the Transmission System at the time of the Transmission Owner's most recent seasonal system peaks (Transmission Owner must provide the Local Distribution Company the day and hour of such peak no later than September 1); and

(b) no later than February 1 of each year:

(i) annual peak demand forecasts in MW for each Local Distribution Company Interconnection Point to the Transmission System for the next five (5) years, or as determined by the Planning Committee, together with corresponding projected power factors; and

(ii) planned facility (new Interconnection Points) connections to the Transmission System for the next five (5) years, or as determined by the Planning Committee.

ARTICLE 8. Transmission Service Level

8.1 Subject to applicable regulatory approvals, including adherence to Least-Cost planning requirements and principles, adherence to applicable NERC, ECAR or other regional reliability council or successor organization's reliability requirements, and all other applicable operating reliability criteria and subject to the oversight and direction of the appropriate RTO or ISO, the Transmission Owner shall operate, maintain, plan and construct its Transmission System in accordance with Good Utility Practice to provide the following service levels:

(i) A minimum Steady-State Voltage of 0.97 Per Unit (PU) at all Interconnection Points with Local Distribution Company with all influential Transmission Owner facilities in service (no contingency conditions);

(ii) A minimum Steady-State Voltage of 0.92 PU at all Interconnection Points with the Local Distribution Company influenced by one or more Transmission Owner facilities out of service (contingency conditions);

(iii) A maximum Steady-State Voltage of 1.05 PU at all Interconnection Points with the Local Distribution Company during all operating conditions;

(iv) An adequate Transmission System that shall not load Local Distribution Company facilities above normal ratings during peak load conditions with all influential Transmission Owner facilities in service (no contingency conditions);

(v) An adequate Transmission System that shall not load Local Distribution Company facilities above emergency ratings during peak load conditions with one or more influential Transmission Owner facilities out of service (contingency conditions);

(vi) On a three-year rolling average, experience no more than 0.357 Momentary Outage Events per 138 kV line protective zone (system average) and 0.743 Momentary Outage Events per 345 kV line protective zone (system average) per year. As used in this Article 8 the term “year” shall mean calendar year; and the term “line protective zone” is illustrated and defined as follows: Any given electrical fault on a transmission line will trip specific circuit breakers in a normally functioning system. All of the possible line fault locations that will trip these specific circuit breakers constitute the same line protective zone. Physically, a line protective zone consists of the conductors located between the current transformers that provide sensing to trip the circuit breakers for a line fault;

(vii) Experience no more than three (3) Momentary Outage Events on any given 138 kV line protective zone and two (2) Momentary Outage Events on any given 345 kV line protective zone per year;

(viii) On a three-year rolling average, experience no more than 0.21 Unplanned Outages per 138 kV line protective zone (system average) and 0.18 Unplanned Outages per 345 kV line protective zone (system average) per year;

(ix) Experience no more than four (4) Unplanned Outages on any given 138 kV line protective zone and three (3) Unplanned Outages on any given 345 kV line protective zone per year;

(x) Should the Transmission Owner fail to meet any of the requirements of Section 8.1(vi) or 8.1(viii) by more than 10% two years in a row, the Transmission Owner shall pay, as liquidated damages and not as a penalty, to the Local Distribution Company, an amount equal to one half of one percent (0.5%) of the annual revenue paid by the Local Distribution Company under the applicable transmission tariff; such liquidated damages amount shall be based upon the revenue received

in the second year of such failure. Such liquidated damages amount shall be increased by one half of a percent (0.5%) for each additional 10% by which the Transmission Owner fails to meet the any of the given outage targets, up to a maximum of 4.0% of the annual revenue. Outage events affecting 15% or more of transmission line protective zones within a 24-hour period will not be counted toward the requirements of Section 8.1.

If transmission service does not meet the requirements of this Article 8, Transmission Owner shall present an action plan acceptable to the Local Distribution Company within sixty (60) days of non-compliance of this Article 8 to restore transmission service to the minimum standards as described in this Article 8 in a timely manner. Should the Transmission Owner fail to correct the deficiency(s) within one year of notification from the Local Distribution Company, the Local Distribution Company shall have the right to take corrective action at the Transmission Owner's expense. The Local Distribution Company shall defer taking such actions for corrective measures normally requiring longer than one year to complete, provided the Transmission Owner is diligently pursuing such measures.

8.2 Should the Michigan Public Service Commission (MPSC) adopt service quality standards that the Local Distribution Company must meet that are more stringent than current historical performance; and should the transmission service level provided by the Transmission Owner directly or indirectly influence the Local Distribution Company's ability to meet such standards, the Local Distribution Company will promptly notify the Transmission Owner of such proposal and the Transmission Owner shall have an opportunity to participate either as a party or in cooperation with the Distribution Company, in any related MPSC hearings or proceedings. Subject to the foregoing and to any required approval by FERC, the Transmission Owner shall be responsible for meeting its proportional share of the adopted service quality standard and for any penalties that might be assessed if the standards are not met.

8.3 Transmission Owner and the Local Distribution Company acknowledge that the Special Manufacturing Contracts in existence at the time of the original execution of the 2001 Amendment and Restatement of the Distribution-Transmission Interconnection Agreement and previously listed under this Exhibit 3 are no longer in effect or no longer have clauses with compensable disruptions/interruptions associated with them. As such, the Parties have agreed to omit Exhibit 3.

ARTICLE 9. New Construction and Modification

9.1 Subject to this Article 9, Transmission Owner may construct additional Transmission System elements or modify the existing Transmission System and Local Distribution Company may construct additional Distribution System

elements or modify the existing Distribution System. All such modifications and construction provided for herein, shall be conducted in accordance with Good Utility Practice and all applicable NERC and ECAR Standards. The Party that modifies the system elements or constructs new system elements is obligated to maintain the transmission, distribution and communications capabilities of the other Party in accordance with Good Utility Practice to avoid or minimize any adverse impact on the other Party. The Parties shall look to the operating history of the Local Distribution Company in the relevant geographic area prior to the Effective Date of this Agreement, where available, in determining what constitutes Good Utility Practice.

9.2 Notwithstanding the foregoing, no modifications to or new construction of facilities or access thereto, including but not limited to rights-of-way, fences, and gates, shall be made by either Party which might reasonably be expected to have a material effect upon the other Party with respect to operations or performance under this Agreement, without providing the other Party with sufficient information regarding the work prior to commencement to enable such Party to evaluate the impact of the proposed work on its operations. The information provided must be of sufficient detail to satisfy reasonable Transmission Owner or Local Distribution Company review and operational requirements. Each Party shall use reasonable efforts to minimize any adverse impact on the other Party.

9.3 If any Party intends to install any new facilities, equipment, systems, or circuits or any modifications to existing or future facilities, equipment, systems or circuits that could reasonably be expected to have a material effect upon the operation of the other Party, the Party desiring to perform said work shall, in addition to the requirements of Section 9.2, provide the other Party with drawings, plans, specifications and other necessary documentation for review at least 60 days prior to the start of the construction of any such installation. This notice period shall not apply to modifications or new installations made to resolve or prevent pending Emergency or Network Security Conditions.

9.4 The Party reviewing any drawings, plans, specifications, or other necessary documentation for review shall promptly review the same and provide any comments to the performing Party no later than 30 days prior to the start of the construction of any installation. Unless system modifications are required in association with the addition of generation to the system (in which case Section 9.8 hereof shall apply) all such reviews shall be performed at no cost to either Party. The performing Party shall incorporate all requested modifications to the extent required in accordance with Good Utility Practice and compliance with this Agreement.

9.5 Within 180 days following placing in-service of any modification or construction subject to this Article 9, the Party initiating the work shall provide “as built” drawings, plans and related technical data to the other Party. Approval or review of any document referenced herein shall not relieve the initiating Party of its responsibility for the design or construction of any proposed facility, nor shall it

subject the other Party to any liability, except with respect to the confidentiality provisions of Article 20.

9.6 Each Party shall, at its own expense, have the right to inspect or observe all maintenance activities, equipment tests, installation work, construction work, and modification work to the facilities of the other Party that could have a material effect upon the facilities or operations of the first Party.

9.7 Construction and installation of any facility shall meet all or exceed all environmental permitting requirements, reviews or approvals as required by federal, state or local law prior to the installation of such facilities. The Parties agree to coordinate environmental permitting related activities such as site review for regulated resources, permit application and project oversight (e.g. monitoring as applicable).

9.8 Whenever system modifications are required to connect generating facilities to either the Local Distribution Company's or the Transmission Owner's system it is expected that the party installing the generating facilities will normally be responsible for much or all of the associated costs. The Parties agree to cooperate in sharing information regarding such projects and to individually make arrangements with the party adding the generation to obtain payment of all related costs as appropriate.

ARTICLE 10. Access to Facilities

10.1 The Parties hereby agree to provide each other reasonable access to their respective property as may be necessary and appropriate to enable each Party to operate and maintain its respective facilities and equipment on such property. Such right of access shall be provided in a manner so as not to unreasonably interfere with either Party's ongoing business operations, rights, and obligations.

10.2 Each Party shall provide the other Party keys, access codes or other access methods necessary to enter the other Party's facilities to exercise rights under this Agreement. Access shall only be granted to Qualified Personnel.

ARTICLE 11. Notifications and Reporting

11.1 Unless otherwise provided, any notice required to be given by either Party to the other Party in connection with this Agreement shall be given in writing: (a) personally; (b) by facsimile transmission (if sender thereafter sends such notice to recipient by any of the other methods provided in this Section 11.1; (c) by registered or certified U.S. mail, return receipt requested, postage prepaid; or (d) by reputable overnight carrier, with acknowledged receipt of delivery; or (e) any other method mutually agreed by the Parties in writing. Notice shall be deemed given on the date of receipt personally. Notice sent by facsimile shall be deemed given on the date the transmission is confirmed by sender's facsimile machine, so long as the facsimile is sent on a business day during normal business hours of the recipient. Otherwise, the notice shall be deemed given on

the next succeeding business day. Notice provided by mail or overnight courier shall be deemed given at the date of acceptance or refusal of acceptance shown on such receipt.

11.2 Notice to the Transmission Owner shall be to the Transmission Owner's Representative, at the addresses identified in Exhibit 2. Notice to the Local Distribution Company shall be to the Local Distribution Company's Representative, at the addresses identified in Exhibit 2.

11.3 Each Party shall provide prompt notice describing the nature and extent of the condition, the impact on operations, and all corrective action, to the other Party of any Emergency or Network Security Condition which may be reasonably anticipated to affect the other Party's equipment, facilities, or operations. Either Party may take reasonable and necessary action, both on its own and the other Party's system, equipment, and facilities, to prevent, avoid or mitigate injury, danger, damage or loss to its own equipment and facilities, or to expedite restoration of service; provided however, that the Party taking such action shall give the other Party prior notice, if at all possible, before taking any action on the other Party's system, equipment, or facilities.

11.4 In the event of an Emergency or Network Security Condition contemplated by Section 11.3, each Party shall provide the other with such information, documents, and data necessary for operation of the Transmission System and Distribution System, including, without limitation, such information which is to be supplied to any Governmental Authority, NERC, ECAR, or Transmission System Operations Center or Distribution System Control Center.

11.5 In order to continue interconnection of the Distribution System and Transmission System, each Party shall promptly provide the other Party with all relevant information, documents, or data regarding the Distribution System and the Transmission System that would be expected to affect the Distribution System or Transmission System, and which is reasonably requested by NERC, ECAR, or any Governmental Authority.

11.6 For routine maintenance and inspection activities on either Parties system that will require major equipment or system outages, and could impact the other Party's system, the Party performing the same shall provide the other Party with not less than seventy-two (72) hours prior notice, if practicable; provided that the provisions of Section 3.9 remain applicable to the outages, and said notice is in addition to, and does not substitute for, the requirements of Section 3.9 (maintenance and inspection activities in generating plant substations require 20 working days notification).

11.7 Transmission Owner shall notify Local Distribution Company prior to entering Local Distribution Company's facilities for routine measurements, inspections and meter reads in accordance with the requirements of Section 11.6. Local Distribution Company shall notify Transmission Owner prior to entering

Transmission Owner's facilities, including switchyards, for routine maintenance, operations, measurements, inspections and meter reads, in accordance with the requirements of Section 11.6.

11.8 Each Party shall provide prompt verbal notice to the other Party of any system alarm that applies to the other Party's equipment, unless the system alarm is automatically sent to the other Party.

11.9 Each Party shall provide a report or a copy of the data from a system events recorder, SCADA system sequence of events or digital fault recorder that applies to the other Party's equipment.

11.10 Each Party agrees to immediately notify the other Party verbally, and then in writing, of any labor dispute or anticipated labor dispute of which its management has actual Knowledge that might reasonably be expected to affect the operations of the other Party with respect to this Agreement.

ARTICLE 12. Safety

12.1 Each Party agrees that all work performed by either Party that may reasonably be expected to affect the other Party shall be performed in accordance with Good Utility Practice and all applicable laws, regulations, safety standards, practices and procedures and other requirements pertaining to the safety of Persons or property, (including, but not limited to those of the Occupational Safety and Health Administration, the National Electrical Safety Code and those developed or accepted by Transmission Owner and Local Distribution Company for use on their respective systems) when entering or working in the other Party's property or facilities or switching area. A Party performing work within the boundaries of the other Party's facilities must abide by the safety rules applicable to the site.

12.2 Each Party shall be solely responsible for the safety and supervision of its own employees, agents, representatives, and subcontractors.

12.3 Transmission Owner shall immediately report any injuries that occur while working on the Local Distribution Company's property or facilities or switching area to appropriate agencies and the Local Distribution Company's Site Representative. Local Distribution Company shall immediately report any injuries that occur while working on the Transmission Owner's property or facilities or switching area to appropriate agencies and the Transmission Owner's Site Representative. Each Party will provide the other with its clearing/tagging/lockout procedures. For clearances requested or initiated by the Local Distribution Company on the Local Distribution Company's equipment that utilizes the Transmission Owner's equipment as an isolation device, Local Distribution Company procedures shall govern. For clearances requested or initiated by the Transmission Owner on the Transmission Owner's equipment that utilizes the Local Distribution Company's equipment as an isolation device,

Transmission Owner procedures shall govern. Under no circumstances shall either Party remove the other Party's protective tags without proper authorization.

ARTICLE 13. Environmental Compliance and Procedures

13.1 Release Prevention and Response. Each Party shall notify the other Party, verbally within 24 hours upon discovery of any Release of any Regulated Substance caused by the Party's operations or equipment that impacts the property or facilities of the other Party, or which may migrate to, or adversely impact the property, facilities or operations of the other Party and shall promptly furnish to the other Party copies of any reports filed with any governmental agencies addressing such events. Such verbal notification shall be followed by written notification within five (5) days. The Party responsible for the Release of any Regulated Substance on the property or facilities of the other Party, or which may migrate to, or adversely impact the property, facilities or operations of the other Party shall be responsible for: (1) the cost and completion of reasonable remediation or abatement activity for that Release, and; (2) required notifications to governmental agencies and submitting of all reports or filings required by environmental laws for that Release. Advance written notification (except in Emergency situations, in which verbal, followed by written notification, shall be provided as soon as practicable) shall be provided to the other Party by the Party responsible for any remediation or abatement activity on the property or facilities of the other Party, or which may adversely impact the property, facilities, or operations of the other Party. Except in Emergency situations such remediation or abatement activity shall be performed only with the consent of the Party owning the affected property or facilities.

13.2 The Parties agree to coordinate, to the extent necessary, the preparation of site plans, reports, environmental permits, clearances and notifications required by federal and state law or regulation, including but not limited to Spill Prevention, Control and Countermeasures (SPCC), Storm Water Pollution Prevention Plans (SWPP), Act 451 Part 31 Part 5 Rules, CERCLA, EPCRA, TSCA, soil erosion and sedimentation control plans (SESC) or activities, wetland or other water-related permits, threatened or endangered species reviews or management and archeological clearances or notifications required by any regulatory agency or competent jurisdiction. Notification of permits applied for and/or received will occur in a timeframe manner suitable to the interests of both Parties.

ARTICLE 14. Billings and Payment

14.1 Any invoices payable under this Agreement shall be provided to the other Party under this Agreement during the preceding month. Invoices shall be prepared within a reasonable time after the first day of each month. Each invoice shall delineate the month in which services were provided, shall fully describe the services rendered and shall be itemized to reflect the services performed or provided. The invoice shall be paid within twenty (20) days of the invoice date, or the first business day thereafter if the payment date falls on other than a

business day. All payments shall be made in immediately available funds payable to the other Party, or by wire transfer to a bank of the Party being paid, provided that payments expressly required by this Agreement to be mailed shall be mailed in accordance with Section 14.2.

14.2 Any payments required to be made by Local Distribution Company under this Agreement shall be made to Transmission Owner at the following address:

Michigan Electric Transmission Company, LLC
P.O. Box 673971
Detroit, MI 48267-3971

Any payments required to be made by Transmission Owner under this Agreement shall be made to Local Distribution Company at the following address:

Consumers Energy Company
One Energy Plaza
Jackson, MI 49201
Attention: Treasurer

14.3 The rate of interest on any amount not paid when due shall be equal to the Interest Rate in effect at the time such amount became due. Interest on delinquent amounts shall be calculated from the due date of the invoice to the date of the payment. When payments are made by mail, invoices shall be considered as having been paid on the date of receipt by the other Party. Nothing contained in this article is intended to limit either Party's remedies under Article 21 of this Agreement.

14.4 Payment of an invoice shall not relieve the paying Party from any responsibilities or obligations it has under this Agreement, nor shall such payment constitute a waiver of any claims arising hereunder.

14.5 If all or part of any bill is disputed by a Party, that Party shall promptly pay the amount that is not disputed and provide the other Party a reasonably detailed written explanation of the basis for the dispute pursuant to Article 26. While the dispute is being resolved, the Parties shall continue to provide services and pay all invoiced amounts not in dispute. Following resolution of the dispute, the prevailing Party shall be entitled to receive the disputed amount, as finally determined to be payable, along with interest accrued at the Interest Rate through the date on which payment is made, within ten (10) business days of such resolution.

14.6 Subject to the Confidentiality provisions of Article 20, within two (2) years following a calendar year, during normal business hours, Local Distribution Company and Transmission Owner shall have the right to audit each other's accounts and records pertaining to transactions under this Agreement that occurred during such calendar year at the offices where such accounts and records are maintained; provided that the audit shall be limited to those portions

of such accounts and records that reasonably relate to the services provided to the other Party under this Agreement for said calendar year. The Party being audited shall be entitled to review the audit report and any supporting materials. To the extent that audited information includes Confidential Information, the auditing Party shall keep all such information confidential pursuant to Article 20.

14.7 Neither Party shall be responsible for the other Party's costs of collecting amounts due under this Agreement, including attorney fees and expenses and the expenses of arbitration.

ARTICLE 15. Applicable Regulations and Interpretation

15.1 Each Party's performance under this Agreement is subject to the condition that all requisite governmental and regulatory approvals for such performance are obtained in form and substance satisfactory to the other Party in its reasonable judgment. Each Party shall exercise Due Diligence and shall act in good faith to secure all appropriate approvals in a timely fashion.

15.2 This Agreement and all rights, obligations, and performances of the Parties hereunder, are subject to present or future state or federal laws, regulations, or orders properly issued by state or federal bodies having jurisdiction. When not in conflict with or pre-empted by federal law, this Agreement shall be interpreted pursuant to the laws of the State of Michigan, exclusive of its conflicts of law principles.

ARTICLE 16. Force Majeure

16.1 An event of Force Majeure means any act of God, labor disturbance, act of the public enemy, war, insurrection, riot, fire, storm or flood, explosion, breakage or accident to machinery or equipment, any curtailment, order, regulation, or restriction imposed by governmental military or lawfully established civilian authorities, or any other cause beyond a Party's reasonable control. A Force Majeure event does not include an act of negligence or intentional wrongdoing.

16.2 If either Party is rendered unable, wholly or in part, by Force Majeure, to carry out its obligations under this Agreement, then, during the continuance of such inability, the obligation of such Party shall be suspended except that Transmission Owner's and Local Distribution Company's obligation under Section 16.3 of this Agreement to provide protection shall not be suspended. The Party relying on Force Majeure shall give written notice of Force Majeure to the other Party as soon as practicable after such event occurs. Upon the conclusion of Force Majeure, the Party heretofore relying on Force Majeure shall, with all reasonable dispatch, take all necessary steps to resume the obligation previously suspended.

16.3 Any Party's obligation to make payments already owing shall not be suspended by Force Majeure.

ARTICLE 17. Indemnification and Limitation on Liability

17.1 Each Party shall at all times assume all liability for, and shall indemnify and save the other Party harmless from any and all damages, losses, claims, demands, suits, recoveries, costs, legal fees, expenses for injury to or death of any Person or Persons whomsoever, or for any loss, destruction of or damage to any property of third persons, firms, corporations or other entities that occurs on its own system and that arises out of or results from, either directly or indirectly, its own facilities or facilities controlled by it, unless caused by the sole negligence, or intentional wrongdoing, of the other Party.

17.2 NEITHER PARTY SHALL BE LIABLE TO THE OTHER FOR ANY SPECIAL, INCIDENTAL, EXEMPLARY, PUNITITIVE OR CONSEQUENTIAL DAMAGES SUCH AS, BUT NOT LIMITED TO, LOST PROFITS, REVENUE OR GOOD WILL, INTEREST, LOSS BY REASON OF SHUTDOWN OR NON-OPERATION OF EQUIPMENT OR MACHINERY, INCREASED EXPENSE OF OPERATION OF EQUIPMENT OR MACHINERY, COST OF PURCHASED OR REPLACEMENT POWER OR SERVICES OR CLAIMS BY CUSTOMERS, WHETHER SUCH LOSS IS BASED ON CONTRACT, WARRANTY, NEGLIGENCE, STRICT LIABILITY OR OTHERWISE.

ARTICLE 18. Insurance

18.1 The Parties agree to maintain, at their own cost and expense, the following insurance coverages for the life of this Agreement in the manner and amounts, at a minimum, as set forth below:

(a) Workers' Compensation Insurance in accordance with all applicable State, Federal, and Maritime Law.

(b) Employer's Liability insurance in the amount of $1,000,000 per accident.

(c) Commercial General Liability or Excess Liability Insurance in the amount of $25,000,000 per occurrence.

(d) Automobile Liability Insurance for all owned, non-owned, and hired vehicles in the amount of $5,000,000 each accident.

18.2 A Party may, at its option, [A] be an approved self-insurer by the State of Michigan for the insurances required in 1.(a) and (d); and [B] maintain such deductibles and/or retentions under the insurance required in 1.(b) and (c) as is maintained by other similarly situated companies engaged in a similar business. The Parties agree that all amounts of self-insurance, retentions and/or deductibles are the responsibility of, and shall be borne by, the Party whom makes such an election.

18.3 Within fifteen (15) days of the Effective Date and thereafter when requested, in writing, but not more than once every 12 months, during the term of this

Agreement (including any extensions) each Party shall provide to the other Party properly executed and current certificates of insurance or evidence of approved self-insurance status with respect to all insurance required to be maintained by such Party under this Agreement. Certificates of insurance shall provide the following information:

(a) Name of insurance company, policy number and expiration date.

(b) The coverage maintained and the limits on each, including the amount of deductibles or retentions, which shall be for the account of the Party maintaining such policy.

(c) The insurance company shall endeavor to provide thirty (30) days prior written notice of cancellation to the certificate holder.

ARTICLE 19. Several Obligations

19.1 Except where specifically stated in this Agreement to be otherwise, the duties, obligations and liabilities of the Parties are intended to be several and not joint or collective. Nothing contained in this Agreement shall ever be construed to create an association, trust, partnership, or joint venture or to impose a trust or partnership duty, obligation or liability or agency relationship on or with regard to either Party. Each Party shall be individually and severally liable for its own obligations under this Agreement.

ARTICLE 20. Confidentiality

20.1 (a) "Confidential Information" shall mean any confidential, proprietary or trade secret information of a plan, specification, pattern, procedure, design, device, list concept, policy or compilation relating to the present or planned business of a Party, which is designated in good faith as Confidential by the Party supplying the information, whether conveyed orally, electronically, in writing, through inspection or otherwise. Confidential Information shall include, without limitation, all information relating to a Party's technology, research and development, business affairs, and pricing, customer-specific load data that constitutes a trade secret, and any information supplied by either of the Parties to the other prior to the execution of this Agreement.

(b) General. Each Party will hold in confidence any and all Confidential Information unless (1) compelled to disclose such information by judicial or administrative process or other provisions of law or as otherwise provided for in this Agreement, or (2) to meet obligations imposed by FERC or by a state or other federal entity or by membership in NERC or ECAR (including other Transmission Owners). Information required to be disclosed under (b)(1) or (b)(2) above, does not, by itself, cause any information provided by Local Distribution Company to Transmission Owner to lose its confidentiality. To the extent it is necessary for either Party to release or disclose such information to a third party in order to perform that Party's obligations herein,

such Party shall advise said third party of the confidentiality provisions of this Agreement and use its best efforts to require said third party to agree in writing to comply with such provisions. Each party will develop and file with FERC standards of conduct relating to the sharing of a market-related Confidential Information with and by their employees.

(c) Term: During the term of this Agreement, and for a period of three (3) years after the expiration or termination of this Agreement, except as otherwise provided in this Article 20, each Party shall hold in confidence and shall not disclose to any Person Confidential Information.

(d) Standard of Care: Each Party shall use at least the same standard of care to protect Confidential Information it receives as that it uses to protect its own Confidential Information from unauthorized disclosure, publication or dissemination.

20.2 Scope: Confidential Information shall not include information that the receiving Party can demonstrate: (1) is generally available to the public other than as a result of disclosure by the receiving Party; (2) was in the lawful possession of the receiving Party on a non-confidential basis prior to receiving it from the disclosing Party; or (3) was supplied to the receiving Party without restriction by a third party, who, to the Knowledge of the receiving Party, after due inquiry was under no obligation to the disclosing Party to keep such information confidential; (4) was independently developed by the receiving Party without reference to Confidential Information of the disclosing Party; (5) is, or becomes, publicly known, through no wrongful act or omission of the receiving Party or breach of this Agreement; or (6) is required, in accordance with Section 20.1(b) of this Agreement, to be disclosed by any federal or state government or agency or is otherwise required to be disclosed by law or subpoena, or is necessary in any legal proceeding establishing rights and obligations under this Agreement. Information designated as Confidential Information will no longer be deemed confidential if the Party that designated the information as confidential notifies the other Party that it no longer is confidential.

20.3 Order of Disclosure. If a court or a government agency or entity with the right power, and apparent authority to do so requests or requires either Party, by subpoena, oral deposition, interrogatories, requests for production of documents, administrative order, or otherwise, to disclose Confidential Information, that Party shall provide the other Party with prompt notice of such request(s) or requirement(s) so that the other Party may seek an appropriate protective order or waive compliance with the terms of this Agreement. The notifying Party shall have no obligation to oppose or object to any attempt to obtain such production except to the extent requested to do so by the disclosing Party and at the disclosing Party's expense. If either Party desires to object or oppose such production, it must do so at its own expense. The disclosing Party may request a protective order to prevent any Confidential Information from being made public. Notwithstanding the absence of a protective order or waiver, the Party may

disclose such Confidential Information which, in the opinion of its counsel, the Party is legally compelled to disclose. Each Party will use reasonable effort to obtain reliable assurance that confidential treatment will be accorded any Confidential Information so furnished.

20.4 Use of Information or Documentation. Each Party may utilize information or documentation furnished by the disclosing Party and subject to Section 20.1 in any proceeding under Article 26 or in an administrative agency or court of competent jurisdiction addressing any dispute arising under this Agreement, subject to a confidentiality agreement with all participants (including, if applicable, any arbitrator) or a protective order.

20.5 Remedies Regarding Confidentiality. The Parties agree that monetary damages by themselves will be inadequate to compensate a Party for the other Party's breach of its obligations under this article. Each Party accordingly agrees that the other Party is entitled to equitable relief, by way of injunction or otherwise, if it breaches or threatens to breach its obligations under this article.

ARTICLE 21. Breach, Default and Remedies

21.1 General. A breach of this Agreement ("Breach") shall occur upon the failure by a Party to perform or observe a material term or condition of this Agreement. A default of this Agreement ("Default") shall occur upon the failure of a Party in Breach of this Agreement to cure such Breach in accordance with Section 21.4.

21.2 Events of Breach. A Breach of this Agreement shall include:

(a) The failure to pay any amount when due;

(b) The failure to comply with any material term or condition of this Agreement, including but not limited to any material Breach of a representation, warranty or covenant made in this Agreement;

~~(b)~~ (c) A Party's abandonment of its work or the facilities contemplated in this Agreement;

~~(c)~~ (d) If a Party: (1) becomes insolvent; (2) files a voluntary petition in bankruptcy under any provision of any federal or state bankruptcy law or shall consent to the filing of any bankruptcy or reorganization petition against it under any similar law; (3) makes a general assignment for the benefit of its creditors; or (4) consents to the appointment of a receiver, trustee or liquidator;

~~(d)~~ (e) Failure of either Party to provide information or data to the other Party as required under this Agreement, provided the Party entitled to the information or data under this Agreement requires such information or data to satisfy its obligations under this Agreement.

21.3 Continued Operation. Except as specifically provided in this Agreement, in the event of a Breach or Default by either Party, the Parties shall continue to operate and maintain, as applicable, facilities and appurtenances that are reasonably necessary for the Transmission Owner to operate and maintain the Transmission System, or the Local Distribution Company to operate and maintain the Distribution System, in a safe and reliable manner.

21.4 Cure and Default. Upon the occurrence of an event of Breach, the non-Breaching Party, when it becomes aware of the Breach, shall give written notice of the Breach to the Breaching Party and to any other Person a Party to this Agreement identifies in writing to the other Party in advance. Such notice shall set forth, in reasonable detail, the nature of the Breach, and where known and applicable, the steps necessary to cure such Breach. Upon receiving written notice of the Breach hereunder, the Breaching Party shall have thirty (30) days, to cure such Breach. If the breach is such that it cannot be cured within thirty (30) days, the Breaching Party will commence in good faith all steps as are reasonable and appropriate to cure the Breach within such thirty (30) day time period and thereafter diligently pursue such action to completion. In the event the Breaching Party fails to cure the Breach, or to commence reasonable and appropriate steps to cure the Breach, within thirty (30) days of becoming aware of the Breach, the Breaching Party will be in Default of the Agreement. In the event of a Default, the non-Defaulting Party has the right to take whatever action at law or equity as may be permitted under this Agreement.

21.5 Right to Compel Performance. Notwithstanding the foregoing, upon the occurrence of an event of Default, the non-Defaulting Party shall be entitled to Commence an action to require the Defaulting Party to remedy such Default and specifically perform its duties and obligations hereunder in accordance with the terms and conditions hereof, and exercise such other rights and remedies as it may have in equity or at law.

ARTICLE 22. Term

22.1 Term. This Agreement shall become effective as of the Effective Date and shall continue in full force and effect so long as any Interconnection Point is connected to the Transmission System, except that it may be terminated by mutual agreement of the Parties.

22.2 Material Adverse Change.

(a) In the event of a material change in law or regulation that adversely affects, or may reasonably be expected to adversely affect, either Party's performance under this Agreement, including but not limited to the following:

(i) this Agreement is not accepted for filing by the FERC without material modification or condition;

(ii) NERC or ECAR prevents, in whole or in part, either Party from performing any provision of this Agreement in accordance with its terms; or

(iii) The FERC, the United States Congress, any state, or any federal or state regulatory agency or commission implements any change in any law, regulation, rule or practice which materially affects or is reasonably expected to materially affect either Party's ability to perform under this Agreement.

The Parties will negotiate in good faith any amendment or amendments to the Agreement necessary to adapt the terms of this Agreement to such change in law or regulation, and the Transmission Owner shall file such amendment or amendments with FERC.

(b) If the Parties are unable to reach agreement on any such amendments, then the Parties shall continue to perform under this Agreement to the maximum extent possible, taking all reasonable steps to mitigate any adverse effect on each other resulting from the Event. If the Parties are unable to reach agreement on any such amendments, Transmission Owner shall have the right to make a unilateral filing with FERC to modify this Agreement pursuant to Section 205 of the Federal Power Act and Local Distribution Company shall have the right to make a unilateral filing with FERC to modify this Agreement pursuant to Section 206 of the Federal Power Act. Each Party shall have the right to protest any such filing by the other Party and to participate fully in any proceeding before FERC.

22.3 Survival. The applicable provisions of this Agreement shall continue in effect after expiration, cancellation or termination hereof to the extent necessary to provide for final billings, billing adjustments and the determination and enforcement of liability and indemnification obligations arising from acts or events that occurred while this Agreement was in effect.

ARTICLE 23. Assignment/Change in Corporate Identity

23.1 Transmission Owner Assignment Rights. Transmission Owner may not assign this Agreement or any of its rights, interests, or obligations hereunder without the prior written consent of Local Distribution Company, which consent shall not be unreasonably withheld; provided however, that Transmission Owner may assign this Agreement or any of its rights or obligations hereunder without the prior consent of Local Distribution Company and may assign this Agreement to any entity(ies) in connection with a merger, consolidation, or reorganization, provided that the surviving entity(ies) or assignee owns the Transmission System, agrees in writing to be bound by all the obligations and duties of Transmission Owner provided for in this Agreement and the assignee's creditworthiness is equal to or higher than that of Transmission Owner.

23.2 Local Distribution Company Assignment Rights. Local Distribution Company may not assign this Agreement or any of its rights, interests or obligations hereunder without the prior written consent of Transmission Owner, which consent shall not be unreasonably withheld; provided however, that Local Distribution Company may, without the consent of Transmission Owner, and by providing prior reasonable notice under the circumstances to Transmission Owner, assign, this Agreement to any entity(ies) in connection with a merger, consolidation, or reorganization, provided that the surviving entity(ies) or assignee owns the Local Distribution Company, agrees in writing to be bound by all the obligations and duties of Local Distribution Company provided for in this Agreement and the assignee's creditworthiness is equal to or higher than that of Local Distribution Company.

23.3 Assigning Party to Remain Responsible. Any assignments authorized as provided for in this article will not operate to relieve the Party assigning this Agreement or any of its rights, interests, or obligations hereunder of the responsibility of full compliance with the requirements of this Agreement unless (a) the other Party consents, such consent not to be unreasonably withheld, and (b) the assignee agrees in writing to be bound by all of the obligations and duties of the assigning Party provided for in this Agreement.

23.4 This Agreement and all of the provisions hereof are binding upon, and inure to the benefit of, the Parties and their respective successors and permitted assigns.

ARTICLE 24. Subcontractors

24.1 Nothing in this Agreement shall prevent the Parties from utilizing the services of subcontractors as they deem appropriate; provided, however, the Parties agree that, where applicable, all said subcontractors shall comply with the terms and conditions of this Agreement.

24.2 Except as provided herein, the creation of any subcontract relationship shall not relieve the hiring Party of any of its obligations under this Agreement. Each Party shall be fully responsible to the other Party for the acts and/or omissions of any subcontractor it hires as if no subcontract had been made. Any obligation imposed by this Agreement upon the Parties, where applicable, shall be equally binding upon and shall be construed as having application to any subcontractor.

24.3 No subcontractor is intended to be or shall be deemed a third-party beneficiary of this Agreement.

24.4 The obligations under this Article shall not be limited in any way by any limitation on subcontractor's insurance.

24.5 Each Party shall require its subcontractors to comply with all federal and state laws regarding insurance requirements and shall maintain standard and ordinary insurance coverages.

ARTICLE 25. Dispute Resolution

Any dispute between the parties arising out of or relating to this Contract or the breach thereof shall be brought to the Administrative Committee. If the Administrative Committee can resolve the dispute, such resolution shall be reported in writing to and shall be binding upon the Parties. If the Administrative Committee cannot resolve the dispute within a reasonable time, the senior officer of Local Distribution Company or the senior officer of Transmission Owner may, by written notice to the senior officer of the other Party and the members of the Administrative Committee, withdraw the matter from consideration by the Administrative Committee and submit the same for resolution to the senior officers of the Parties. If the senior officers of the Parties agree to a resolution of the matter, such resolution shall be reported in writing to, and shall be binding upon, the Parties; but if said senior officers fail to resolve the matter within five (5) Business Days after its submission to them, then the Parties agree to try in good faith to settle the dispute by mediation administered by the American Arbitration Association under its Commercial Mediation Rules before resorting to litigation.

ARTICLE 26. Miscellaneous Provisions

26.1 This Agreement shall constitute the entire Agreement between the Parties hereto relating to the subject matter hereof. In all other respects, special contracts or superseding rate schedules shall govern Transmission Owner's transmission service to Local Distribution Company.

26.2 No failure or delay on the part of Transmission Owner or Local Distribution Company in exercising any of its rights under this Agreement, no partial exercise by either Party of any of its rights under this Agreement, and no course of dealing between the Parties shall constitute a waiver of the rights of either Party under this Agreement. Any waiver shall be effective only by a written instrument signed by the Party granting such waiver, and such shall not operate as a waiver of, or estoppel with respect to, any subsequent failure to comply therewith.

26.3 Nothing in this Agreement, express or implied, is intended to confer on any other Person except the Parties hereto any rights, interests, obligations, or remedies hereunder.

26.4 In the event that any clause or provision of this Agreement or any part hereof shall be held to be invalid, void, or unenforceable by any court or Governmental Authority of competent jurisdiction, said holding or action shall be strictly construed and shall not affect the validity or effect of any other provision hereof, and the Parties shall endeavor in good faith to replace such invalid or unenforceable provisions with a valid and enforceable provision which achieves the purposes intended by the Parties to the greatest extent permitted by law.

26.5 The article and section headings herein are inserted for convenience only and are not to be construed as part of the terms hereof or used in the interpretation of this Agreement.

26.6 In the event an ambiguity or question of intent or interpretation arises, this Agreement shall be construed as if drafted jointly by the Parties and no presumption or burden of proof shall arise favoring or disfavoring any Party by virtue of authorship of any of the provisions of this Agreement. Any reference to any federal, state, local, or foreign statute or law shall be deemed also to refer to all rules and regulations promulgated thereunder, unless the context requires otherwise. The word “including” in this Agreement shall mean including without limitation.

26.7 This Agreement may be executed in one or more counterparts, each of which shall be deemed an original.

26.8 Each Party shall act as an independent contractor with respect to the provision of services hereunder.

IN WITNESS WHEREOF, Transmission Owner and Local Distribution Company have caused this instrument to be executed by their duly authorized representatives as of the day and year first above written.

CONSUMERS ENERGY COMPANY

By:_____

Name: Tonya Berry

Title: Senior Vice President Transformation and Engineering

MICHIGAN ELECTRIC TRANSMISSION COMPANY, LLC, a Michigan limited liability company

By: ITC Holdings Corp., a Michigan corporation, its sole manager

By:_____

Name: Brian Slocum

Title: Senior Vice President and Chief Operating Officer

EXHIBIT 1 – Interconnection Points (Substations)

Addendum 143 - ~~November 27, 2023~~October 18, 2024

Substation

1. Abbe
2. Acme (04/10)
3. Alcona
4. Alder Creek
5. Alger
6. Algoma
~~6.~~7. **Alliance (05/24)**
~~7.~~8. Alma
~~8.~~9. Almeda
~~9.~~10. Alpena
~~10.~~11. Alpine
~~11.~~12. Amber
~~12.~~13. American Bumper
~~13.~~14. Arenac (05/23)
~~14.~~15. Arthur (06/06)
~~15.~~16. Ash Road (06/18)
~~16.~~17. Aubil Lake
~~17.~~18. Backus
~~18.~~19. Bagley
~~19.~~20. Bangor
~~20.~~21. Baraga (12/07)
~~21.~~22. Bard Road
~~22.~~23. Barnum Creek
~~23.~~24. Barry
~~24.~~25. Bass Creek
~~25.~~26. Batavia
~~26.~~27. Bay Road
~~27.~~28. Bayberry
~~28.~~29. Beals Road
~~29.~~30. Becker
~~30.~~31. Beaver Creek
~~31.~~32. Beebe
~~32.~~33. Beecher
~~33.~~34. Begole
~~34.~~35. Bell Road
~~35.~~36. Bennington
~~36.~~37. Benston (11/18)
~~37.~~38. Beveridge
~~38.~~39. Bilmar
~~39.~~40. Bingham
~~40.~~41. Birchwood (06/12)
~~41.~~42. Black River
~~42.~~43. Blackman
~~43.~~44. Blackstsone
~~44.~~45. Blinton
~~45.~~46. Blue Water
~~46.~~47. Bluegrass
~~47.~~48. Boardman
~~48.~~49. Boxboard
~~49.~~50. Bricker
~~50.~~51. Brickyard
~~51.~~52. Briggs & Stratton
~~52.~~53. Broadmoor
~~53.~~54. Bronco
~~54.~~55. Broughwell
~~55.~~56. Buck Creek
~~56.~~57. Bullock
~~57.~~58. Busch Road (02/08)
~~58.~~59. Caledonia
~~59.~~60. Calhoun
~~60.~~61. Camelot Lake
62. Campbell 138
~~61. Calvary (05/24)~~
~~62.~~63. Canal
~~63.~~64. Cannon
~~64.~~65. Carpenter Rd (08/06)
~~65.~~66. Carter
67. Cedar Springs
~~66.~~68. **Celery (03/24)**
69. Cement City
~~67.~~70. **Charge (05/24)**
~~68.~~71. Chase
~~69.~~72. Cheesman
~~70.~~73. Chicago
~~71.~~74. Churchill
~~72.~~75. Clare
~~73.~~76. Claremont
~~74.~~77. Clearwater
~~75.~~78. Cleveland
~~76.~~79. Club
~~77.~~80. Cobb
~~78.~~81. Cochran

~~79.~~82. Cole Creek
~~80.~~83. Colony Farm
~~81.~~84. Convis
~~82.~~85. Cork Street
~~83.~~86. Cornell
~~84.~~87. Cottage Grove
~~85.~~88. Covert
~~86.~~89. Cowan Lake
~~87.~~90. Crahen (10/07)
~~88.~~91. Croton
~~89.~~92. David
~~90.~~93. Dean Road
~~91.~~94. Deja
~~92.~~95. Delaney
~~93.~~96. Delhi
~~94.~~97. Denso Jackson
~~95.~~98. Derby
~~96.~~99. Discovery Way (04/11)
~~97.~~100. Dorr Corners
~~98.~~101. Dort
~~99.~~102. Dow Corning
~~100.~~103. Dowling
~~101.~~104. Drake Road
~~102.~~105. Duffield Rd
~~103.~~106. Dupont
~~104.~~107. Duquite
~~105.~~108. Dutton
~~106.~~109. East Paris
~~107.~~110. East Tawas
~~108.~~111. Easton
~~109.~~112. Edenville
~~110.~~113. Edwards (07/21)
~~111.~~114. Ellis
~~112.~~115. Elm Street
~~113.~~116. Elmwood
~~114.~~117. Emmet
~~115.~~118. Englishville
~~116.~~119. Eureka
~~117.~~120. Farr Road
~~118.~~121. Felch Road
~~119.~~122. Filer City
~~120.~~123. Fillmore
~~121.~~124. Flakeboard
~~122.~~125. Forest (12/16)
~~123.~~126. Forest Grove (12/18)
~~124.~~127. Fort Custer
~~125.~~128. Forty Fourth Street
~~126.~~129. Four Mile
~~127.~~130. Gaylord
~~128.~~131. Geddes (04/08)
~~129.~~132. Gleaner
~~130.~~133. Grand Blanc BOC
~~131.~~134. Gratiot
~~132.~~135. Greenwood
~~133.~~136. Grey Iron
~~134.~~137. Grodi Road
~~135.~~138. Gout
~~136.~~139. Hackett
~~137.~~140. Hagadorn
~~138.~~141. Hager Park
~~139.~~142. Halsey
~~140.~~143. Haring
~~141.~~144. Harvard Lake (06/09)
~~142.~~145. Hawthorne (11/22)
~~143.~~146. Hazelwood
~~144.~~147. Hemphill
~~145.~~148. Hendershot
~~146.~~149. Higgins
~~147.~~150. Hile Road
~~148.~~151. Hillman Cogen
~~149.~~152. Hodenpyl
~~150.~~153. Holland Road
~~151.~~154. Hotchkiss
~~152.~~155. Howell Road (12/21)
~~153.~~156. HSC
~~154.~~157. Hubbard Lake (12/07)
~~155.~~158. Huckleberry (05/22)
~~156.~~159. Hubbardston Road (06/10)
~~157.~~160. Hudsonville
~~158.~~161. Hughes Road
~~159.~~162. Hull Street
~~160.~~163. Iosco
164. Island Road
~~161.~~165. ~~Jaguar~~**~~Celery (03/24)~~**
~~162.~~166. Jamestown
~~163.~~167. Karn 138
~~164.~~168. Kentwood
~~165.~~169. Keystone
~~166.~~170. Kinderhook (05/07)
~~167.~~171. Kipp Road
~~168.~~172. Kraft Avenue
~~169.~~173. Kromdyke (04/19)
~~170.~~174. Labarge
~~171.~~175. Lafayette
~~172.~~176. Latimer
~~173.~~177. Laundra (05/07)
~~174.~~178. Lawndale
~~175.~~179. Layton
~~176.~~180. Letts Road

181. Lewiston
~~177. Lincoln (05/24)~~
~~178.~~182. ~~-~~Lindbergh
~~179.~~183. Livingston Peaker
~~180.~~184. Looking Glass
~~181.~~185. Lorin
~~182.~~186. Lovejoy
~~183.~~187. Ludington
~~184.~~188. Maines Road (03/17)
~~185.~~189. Manlius
~~186.~~190. Marquette
~~187.~~191. McGulpin
~~188.~~192. McNally
~~189.~~193. MCV
~~190.~~194. Meadowbrooke
~~191.~~195. Mecosta
~~192.~~196. Medusa
~~193.~~197. Michigan
~~194.~~198. Michigan Power (MPLP)
~~195.~~199. Miles Road
~~196.~~200. Milham
~~197.~~201. Mio
~~198.~~202. Monitor
~~199.~~203. Moore Road
~~200. Morrow~~
~~201.~~204. ~~-~~Mullins
~~202.~~205. Murner (10/19)
~~203.~~206. Muskegon Heights
~~204.~~207. Neff Road
~~205.~~208. Nineteen Mile Road
~~206.~~209. North Belding
~~207.~~210. North Corunna
~~208.~~211. Northern Fibre
~~209.~~212. North Star (02/19)
~~210.~~213. Nugent Sand
~~211.~~214. Oakland
~~212.~~215. Oceana
~~213.~~216. Ogemaw
~~214.~~217. Orr Road (03/09)
~~215.~~218. Owosso
~~216.~~219. Packard
~~217.~~220. Page Avenue
~~218.~~221. Palisades
~~219.~~222. Parkville (08/12)
~~220.~~223. Parr Road
~~221.~~224. Parshallville
~~222.~~225. Pasadena
~~223.~~226. Pavilion
~~224.~~227. Pearline (06/11)
~~225.~~228. Pettis Road
~~226.~~229. Pigeon River/Rondo
~~227.~~230. Pingree (10/08)
~~228.~~231. Piston Ring P
~~229.~~232. Plaster Creek
~~230.~~233. Plum (07/10)
~~231.~~234. Plymouth Street
~~232.~~235. Plywood
~~233.~~236. Polkton (11/22)
~~234.~~237. Port Calcite
~~235.~~238. Port Sheldon
~~236.~~239. Porter
~~237.~~240. Portsmouth
~~238.~~241. Price Road (09/07)
~~239.~~242. Progress Street
~~240.~~243. Race Street
~~241.~~244. Raisin
~~242.~~245. Ransom
~~243.~~246. Ratigan (12/12)
~~244.~~247. Regal (01/13)
~~245.~~248. Renaissance
~~246.~~249. Rice Creek
~~247.~~250. Rifle River
251. Riggsville
~~248.~~252. **Riverbend (12/24)**
~~249.~~253. Rivertown
~~250.~~254. Riverview
~~251.~~255. Roedel Road
~~252.~~256. Rogue River (06/07)
~~253.~~257. Ryno (09/14)
~~254.~~258. Saginaw River
~~255.~~259. Samaria
260. Sanderson
~~256.~~261. **Santiago (12~~0~~/24~~3~~)**
~~257.~~262. Savidge
~~258.~~263. Scenic Lake (12/15)
~~259.~~264. Scott Lake
~~260.~~265. Seamless East/Seamless
~~261.~~266. Seven Mile (11/2020)
~~262.~~267. Simmons
~~263.~~268. Simpson (08/12)
~~264.~~269. Smith Creek
~~265.~~270. Snyder (06/17)
~~266.~~271. Sonoma (05/06)
~~267.~~272. Spaulding
~~268.~~273. Spruce Road
~~269.~~274. Stacey
~~270.~~275. Steelcase
~~271.~~276. Stillson
~~272.~~277. Stonegate
~~273.~~278. Stover

~~274.~~279. Stronach
~~275.~~280. Summerton
~~276.~~281. Tallman
~~277.~~282. Technical Drive (01/20)
~~278.~~283. Thetford
~~279.~~284. Thompson Road
~~280.~~285. Tihart
~~281.~~286. Tinsman
~~282.~~287. Tippy
~~283.~~288. Titus Lake
~~284.~~289. Trillium (06/07)
~~285.~~290. Trowbridge
~~286.~~291. Tuscola Bay
~~287.~~292. Twelfth Street
~~288.~~293. Twilight
~~289.~~294. Upjohn
~~290.~~295. Van Atta
~~291.~~296. Van Buren (06/08)
~~292.~~297. Vanderbilt
~~293.~~298. Vernon
~~294.~~299. Verona
~~295.~~300. Vevay
~~296.~~301. Viking Lincoln
~~297.~~302. Vrooman
~~298.~~303. Wakerly
~~299.~~304. Warner
~~300.~~305. Warren
~~301.~~306. Washtenaw
~~302.~~307. Wayland
~~303.~~308. Weadock
~~304.~~309. Wealthy Street
~~305.~~310. West Fenton (05/07)
~~306.~~311. Wexford
~~307.~~312. White Lake
~~308.~~313. White Road
~~309.~~314. Whiting
~~310.~~315. Whittemore
~~311.~~316. Willard
~~312.~~317. Withey Lake (05/06)
~~313.~~318. Zeeland

New Interconnections added for this year's DTIA are shown in **bold type**.

Interconnections added after May of 2002 will have the (month/year) in-service date after the substation name.

Note, this list of substations is not necessarily a list of the true points of facility ownership change between the Transmission Owner and the Local Distribution Company. This also is not a complete listing of all Local Distribution Company substations that have a 138 kV high-side supply voltage.

The generator sites or generator POIs referenced under this Exhibit are referenced herein because Local Distribution Company provides distribution service to the corresponding generators.

EXHIBIT 2 - Contact Information For Local Distribution Company's Representatives and Transmission Owner's Representatives

Local Distribution Company:

Consumers Energy Company
1945 West Parnall Road
Jackson, MI 49201

Attn: Executive Director, Electric Planning

Transmission Owner:

Michigan Electric Transmission Company, LLC
27175 Energy Way
Novi, MI 48377

Attn: Legal Department – General Counsel

Email: jdanna@itctransco.com

EXHIBIT 3

Intentionally Omitted

EXHIBIT 4 – Metering Specifications

Performance criteria:

1. Meters shall meet or exceed the latest version of ANSI C12.16 (Standard for Solid State Electricity Meters) specifications for solid state metering.

2. Current transformers used for metering shall meet or exceed an accuracy class of 0.3%. Secondary connected burdens shall not exceed rated burden of any current transformer. Current transformers shall comply with most current applicable ANSI Standards including C57.13 (IEEE Standard Requirements for Instrument Transformers) and C12.11 (Instrument Transformers for Revenue Metering 10 kV BIL through 350 kV BIL). Meter installations shall comply with manufacturer's accuracy and burden class information on the nameplate of each device.

3. Voltage transformers used for metering shall meet or exceed an accuracy class of 0.3%. Secondary connected burdens shall not exceed rated burden of any voltage transformer. Voltage transformers shall comply with most current applicable ANSI Standards including C57.13 (IEEE Standard Requirements for Instrument Transformers), and C12.11 (Instrument Transformers for Revenue Metering 10 kV BIL through 350 kV BIL). Meter installations shall comply with manufacturer's accuracy and burden class information on the nameplate of each device.

4. PT secondary circuits shall have a disconnect switch installed which provides a visible air gap for worker safety, and which allows for attachment of a protective safety tag.

EXHIBIT 5

Intentionally Omitted

EXHIBIT 6 - Jointly Owned Assets Ownership by Percent of Major Equipment
Addendum 14~~3~~ – ~~November 27, 2023~~October 18, 2024

Substations

Jointly Owned Assets, Percentage Split by Major Equipment Count[1]

Substation Name	Distribution owned by Local Distribution Company	Transmission owned by Transmission Owner	Generation Owned by Local Distribution Company	Third-Party Assets	Last Revision Date
Alder Creek	99.99	0.01			4/15/19
Alma	66.67	33.33			10/24/03
Amber	66.67	33.33			4/15/19
Bangor	33.33	66.67			4/15/19
Bard Road	41.67	58.33			06/10/10
Bass Creek	83.33	16.67			4/15/19
Batavia	53.33	46.67			11/17/22
Bay Road	99.99	0.01			4/15/19
Beals Road	84.62	15.38			06/10/10
Beaver Creek	66.67	33.33			07/15/20
Beecher	77.42	22.58			11/17/22
Bell Road	99.99	0.01			4/15/19
Bennington	99.99	0.01			4/15/19
Beveridge	80.00	20.00			4/15/19
Bingham	57.14	42.86			11/7/23
Black River	66.67	33.33		0.00	4/15/19
Blackman	99.99	0.01			4/15/19
Blackstone	70.83	29.17			11/28/11

1 Notes:

(a) Transmission Owner shall own at least 0.01% of all jointly owned substations regardless of its status regarding ownership of major equipment.

(b) Changes, relative to the previous revision (addendum), are shown in bold type.

(c) At 120kV and above, third-party related assets will be included as part of the Transmission Owner's assets for purposes of making this calculation. Also, the third-party may share in the financial responsibility associated with O&M activities.

(d) Third-party may share in the financial responsibility associated with O&M activities.

(e) Below 120kV the third-party related assets will be included as part of the Local Distribution Company's assets for purposes of making this calculation. Also, the third-party may share in the financial responsibility associated with O&M activities.

Blinton	99.99	0.01			4/15/19
Broadmoor	95.83	4.17			4/15/19
Broughwell	99.99	0.01			4/15/19
Buck Creek	58.33	41.67			11/17/22
Bullock	76.00	24.00			11/20/08
Chase	62.50	37.50			4/15/19
Claremont	68.00	32.00			05/01/02
Cobb	57.69	42.31	0.00		07/15/20
Cork Street	33.33	66.67			4/15/19
Cornell	66.67	33.33			11/27/23
Cottage Grove	99.99	0.01			4/15/19
Croton	59.09	31.82	9.09		4/15/19
Dean Road	99.99	0.01			4/15/19
Delaney	80.00	20.00			4/15/19
Delhi	52.38	47.62			10/02/14
Dort	~~68.18~~99.99	~~31.82~~0.01			~~11/28/11~~10/18/24
Dow Corning	80.00	20.00			4/15/19
Drake Road	99.99	0.01			4/15/19
Dupont	99.99	0.01			4/15/19
Duquite	99.99	0.01			4/15/19
East Paris	99.99	0.01			4/15/19
East Tawas	99.99	0.01			4/15/19
Emmet	61.54	38.46			4/15/19
Eureka	60.00	40.00			11/7/23
Felch Road	83.33	16.67			03/31/06
Four Mile	~~73.33~~88.00	~~26.67~~12.00			~~03/16/06~~10/18/24
Gaylord	55.56	44.44	0.00		4/15/19
Grand Blanc BOC	25.00	75.00			4/15/19
Grey Iron	80.00	20.00			4/15/19
Halsey	76.92	23.08			10/24/03
Hazelwood	85.71	14.29			4/15/19
Hemphill	65.52	34.48			11/27/23
Higgins	68.75	31.25			11/7/23
Holland Road	75.00	25.00			4/15/19
Hotchkiss	99.99	0.01			4/15/19
HSC	33.33	66.67			11/28/11
Iosco	75.00	25.00			4/15/19
Island Road	76.92	23.08			4/15/19
Kentwood	99.99	0.01			4/15/19
Kipp Road	99.99	0.01			4/15/19
Kraft Avenue	99.99	0.01			4/15/19
Lafayette	99.99	0.01			4/15/19
Lawndale	70.59	29.41			11/28/12
Layton	99.99	0.01			4/15/19

Lindbergh	99.99	0.01			4/15/19
Manlius	99.99	0.01			4/15/19
Marquette	61.54	38.46			4/15/19
McGulpin	55.56	44.44			11/28/11
Mecosta	66.67	33.33			4/15/19
Milham	66.67	33.33			11/28/12
Monitor	86.67	13.33			4/15/19
Moore Road	50.00	36.36		13.64	11/17/22
~~Morrow~~	~~67.86~~	~~32.14~~	~~0.00~~		~~4/15/19~~
North Belding	66.67	33.33			10/24/03
Oakland	62.50	37.50			4/15/19
Parr Road	85.71	14.29			4/15/19
Port Calcite	77.78	22.22			4/15/19
Ransom	72.73	27.27			11/23/21
Rice Creek	82.35	17.65			11/27/23
Riggsville	71.43	28.57			11/7/23
Riverview	63.16	36.84			11/23/21
Saginaw River	42.86	57.14			4/15/19
Samaria	90.00	10.00			4/15/19
Scott Lake	77.78	22.22			11/17/22
Spaulding	53.33	46.67			10/02/14
Spruce Road	99.99	0.01			4/15/19
Stover	37.50	62.50			11/23/21
Summerton	91.67	8.33			4/15/19
Tihart	66.67	33.33			11/28/12
Tippy	0.00	66.67	33.33		4/15/19
~~Twining~~	~~0.01~~	~~99.99~~			~~05/26/23~~
Upjohn	75.00	25.00			4/15/19
Vanderbilt	99.99	0.01			4/15/19
Verona	56.52	43.48			07/15/20
Vevay	99.99	0.01			4/15/19
Vrooman	62.50	37.50			4/15/19
Wackerly	90.00	10.00			4/15/19
Warner	99.99	0.01			4/15/19
Warren	81.82	18.18			4/15/19
Weadock	59.09	40.91	0.00		4/15/19
Wealthy Street	85.71	14.29			4/15/19
Wexford	85.71	14.29			4/15/19
White Lake	82.35	17.65			11/17/22
White Road	99.99	0.01			4/15/19
Whiting	53.85	46.15	0.00		4/15/19
Whittemore	99.99	0.01			4/15/19

FERC rendition of the electronically filed tariff records in Docket No. ER25-00868-000

Filing Data:

CID	Filing Title	Company Filing Identifier	Type of Filing Code	Associated Filing Identifier
C001344	2025-01-07_SA 1926 METC-CE 11th Rev DTIA	15653	10	
	Tariff Title	**Tariff ID**	**Payment Confirmation**	**Suspension Motion**
	Midwest ISO Agreements	13		

Tariff Record Data:

Record Content Description	**SA 1926**
Tariff Record Title	**DTIA Consumers-METC**
Record Version Number	**39.0.0**
Option Code	**A**
Record Narrative Name	
Tariff Record ID	**4509**
Tariff Record Collation Value	**276950016**
Tariff Record Parent Identifier	**4505**
Proposed Date	**2025-01-01**
Priority Order	**1000000000**
Record Change Type	**CHANGE**
Record Content Type	**1**
Associated Filing Identifier	

SA 1926 METC-CE DTIA VERSION 39.0.0

EFFECTIVE 1/1/2025

ELEVENTH REVISED SERVICE AGREEMENT NO. 1926

AMENDED AND RESTATED DISTRIBUTION-TRANSMISSION INTERCONNECTION AGREEMENT

by and between

Michigan Electric Transmission Company, LLC

as Transmission Provider

and

Consumers Energy Company

as Local Distribution Company

AMENDED AND RESTATED DISTRIBUTION-TRANSMISSION INTERCONNECTION AGREEMENT

by and between

Michigan Electric Transmission Company, LLC

as Transmission Owner

and

Consumers Energy Company

as Local Distribution Company

TABLE OF CONTENTS

AMENDED AND RESTATED

DISTRIBUTION TRANSMISSION INTERCONNECTION AGREEMENT

This Amended and Restated Distribution Transmission Interconnection Agreement ("Agreement") is entered into by and between the Michigan Electric Transmission Company, LLC, a Michigan limited liability company ("Transmission Owner"), having a place of business at 27175 Energy Way, Novi, Michigan 48377, and Consumers Energy Company ("Local Distribution Company"), a Michigan company, doing business in Michigan and having a place of business at One Energy Plaza, Jackson, Michigan, 49201. Transmission Owner and Local Distribution Company are individually referred to herein as a "Party" and collectively as "Parties." This Agreement amends, restates and completely replaces any and all previous versions of the Distribution Transmission Interconnection Agreement between the Parties, and is effective as of January 1, 2025.

WHEREAS, Transmission Owner requires access to parts of Local Distribution Company's assets, and Local Distribution Company requires access to parts of Transmission Owner's assets; and

WHEREAS, the Parties have agreed to execute this mutually acceptable Agreement in order to provide interconnection of the Local Distribution Company with the Transmission Owner and to define the continuing rights, responsibilities, and obligations of the Parties with respect to the use of certain of their own and the other Party's property, assets, and facilities.

NOW, THEREFORE, in consideration of their respective commitments set forth herein, and intending to be legally bound hereby, the Parties covenant and agree as follows:

ARTICLE 1. Definitions

Wherever used in this Agreement with initial capitalization, the following terms shall have the meanings specified or referred to in this Article 1.

1.1 Administrative Committee means the committee established pursuant to Article 6 of the Operating Agreement dated April 1, 2001, as amended and restated, between Local Distribution Company and Transmission Owner.

1.2 Agreement means this Interconnection Agreement between Local Distribution Company and Transmission Owner, including all attachments hereto, as the same may be amended, supplemented, or modified in accordance with its terms

1.3 Black Start Capability shall mean a generating unit that is capable of starting without an outside electrical supply.

1.4 Black Start Plan shall mean a plan utilizing Black Start Capability designed and implemented by the Transmission Owner in conjunction with its interconnected generation and distribution customers, Distribution System Control, other electric

systems, its Security Coordinator and ECAR, to energize portions of the Transmission System which are de-energized as a result of a widespread system disturbance.

1.5 Commission shall mean the Michigan Public Service Commission (MPSC), or its successor.

1.6 Confidential Information shall have the meaning set forth in Section 20.1 hereof.

1.7 Control Area shall mean an electric system, bounded by interconnection metering and telemetry. Generation within the Control Area is directed to operate in a manner prescribed by guidelines established by ECAR and NERC and in accordance with Good Utility Practice to (a) maintain scheduled interchange with other Control Areas, (b) maintain the operating frequency and (c) provide sufficient generating capacity to maintain operating reserves.

1.8 Distribution System shall mean, subject to and consistent with the provisions of Section 3.2 and 3.4 hereof, the equipment and facilities and the Interconnection Equipment owned, or that should be owned by the terms of this Agreement, by the Local Distribution Company and used to deliver power and energy to end users, including transformers, switches, and feeders rated at a Nominal Voltage of 138 kilovolts (kV) or less.

1.9 Distribution System Control shall mean the entity that has the ability and the obligation to operate the Distribution System Control Area to ensure that the aggregate electrical demand and energy requirements of the load is met at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements.

1.10 Distribution System Control Area shall mean a Control Area whose load and generation, and other bulk power supply points are integrated by the Transmission System.

1.11 Distribution System Control Center shall mean the electric Distribution System Control Center(s) that is/are responsible for monitoring and controlling the Distribution System in real time.

1.12 Distribution Transformer shall mean an electrical transformer which, generally, has its secondary low-side windings rated at Nominal Voltage of less than 138 kV.

1.13 Due Diligence shall mean the exercise of good faith efforts to perform a required act on a timely basis and in accordance with Good Utility Practice using the necessary technical and personnel resources.

1.14 ECAR is an acronym, which stands for the East Central Area Reliability coordination agreement. This is the Agreement under which Transmission Providers, who are signatories of the agreement, establish regional coordination

practices and guides to govern the electric coordinated operation and reliability of the East Central Region of North America. As used in this Agreement, the term ECAR includes any successor organization's reliability requirements.

1.15 Effective Date shall mean the closing date as defined in the Membership Interests Purchase Agreement between the Parties.

1.16 Eligible Customer shall have the same meaning as that term is defined under the Transmission Owner's OATT on file with the FERC.

1.17 Emergency means a condition or situation that in the reasonable good faith determination of the affected Party in accordance with Good Utility Practice contributes to an existing or imminent physical threat of danger to life or a significant threat to health, property or the environment.

1.18 Extended Outage shall mean an Unplanned Outage, in which facilities are automatically removed from service (typically by relay-action operating circuit breakers), with a duration of more than two (2) minutes.

1.19 FERC shall mean the Federal Energy Regulatory Commission or its successor federal agency.

1.20 Force Majeure shall have the meaning set forth under Article 16 hereof.

1.21 Forced Outage shall mean an Unplanned Outage, in which facilities are removed from service by operator intervention and not automatically such as by relay-action operating circuit breakers.

1.22 Good Utility Practice shall mean any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather includes all acceptable practices, methods, or acts generally accepted in the region.

1.23 Governmental Authority shall mean any foreign, federal, state, local or other governmental regulatory or administrative agency, court, commission, department, board, or other governmental subdivision, legislature, rulemaking board, tribunal, arbitrating body, or other governmental authority; provided such entity possesses valid jurisdictional authority to regulate the Parties and the terms and conditions of this Agreement.

1.24 ISO means Independent System Operator.

1.25 Interconnection Equipment shall mean all the equipment that is necessary for the interconnection of the Distribution System to the Transmission System which is located at the substations listed in Exhibit 1 hereto as it may be revised from time to time.

1.26 Interconnection Point(s) shall mean the point(s) at which the Distribution System is connected to the Transmission System, as set forth in Exhibit 1 hereto as it may be revised from time to time.

1.27 Interconnection Service shall mean the services provided by the Transmission Owner for the interconnection of the Distribution System with the Transmission System. Interconnection Service does not include the right to transmission service on the Transmission System, which service shall be obtained in accordance with the provisions of the Transmission Owner's OATT.

1.28 Interconnection Standards shall be those standards provided by the Transmission Owner to the Local Distribution Company to establish and maintain interconnection operation in compliance with standards of NERC, ECAR, applicable state or federal regulations or by mutual agreement of the Parties.

1.29 Interest Rate shall mean an annual percentage rate of interest equal to the lesser of (a) the prime rate published by the Wall Street Journal (which represents the base rate on corporate loans posted by at least 75% of the nation's banks) on the date due, plus 2%, or (b) the highest rate permitted by law.

1.30 Jointly Owned Assets shall mean those assets in which the Transmission Owner and Local Distribution Company have undivided ownership interests. Due to the nature of substation designs, many of the supporting substation assets (e.g., station batteries, fence, control houses, ground grid, yard stone, steel structures, and some protective relay equipment) cannot be separated by ownership and the Parties share in the ownership of such assets. The respective ownership of such assets by substation is shown in Exhibit 6.

1.31 Knowledge shall mean actual knowledge of the corporate officers or managers of the specified Person charged with responsibility for the particular function as of the Effective Date of this Agreement, or, with respect to any certificate delivered pursuant to the Agreement, the date of delivery of the certificate.

1.32 Least-Cost shall mean the lowest Transmission System and Distribution System facility costs, over the life of the facility, to accommodate an improvement need while adequately providing for reliability, operating, and maintenance requirements.

1.33 Reserved

1.34 Reserved

1.35 Local Distribution Company shall mean Consumers Energy Company and its successors and assigns.

1.36 Local Distribution Company Provided Services shall mean those services provided by the Local Distribution Company for the Transmission Owner by mutual agreement or contract.

1.37 Local Distribution Company's Representative shall be that person(s) identified as the point of contact for day-to-day operations of the Distribution System, identified in Section 2.3.

1.38 Momentary Outage shall mean a Distribution or Transmission System (in whole or in part) interruption in service with a duration of two (2) minutes or less.

1.39 Momentary Outage Event shall mean one or more Momentary Outages within any 60-minute period that are attributable to the same root cause.

1.40 NERC shall mean the North American Electric Reliability Council or its successor.

1.41 Network Security shall mean the ability of the Transmission System to withstand sudden disturbances such as unforeseen conditions, electric short circuits or unanticipated loss of system elements consistent with reliability principles used to design, plan, operate, and assess the actual or projected reliability of an electric system that are established by any Governmental Authority, NERC or ECAR and which are implemented by Transmission Owner or required of Transmission Owner in compliance with Security Coordinator directives.

1.42 Network Security Condition shall mean a condition or situation in which, in the reasonable good faith determination of Transmission Owner, Network Security is not satisfied or is threatened.

1.43 Nominal Voltage shall mean an accepted standard voltage level offered by the Transmission Owner, at various points on the Transmission System, including but not limited to 120 kV, 138 kV and 345 kV.

1.44 Normal System Condition shall mean any operating conditions of the Transmission System other than an Emergency or Network Security Condition.

1.45 Open Access Transmission Tariff or OATT shall mean the Open Access Transmission Tariff of the Transmission Owner on file with the FERC.

1.46 Operating Committee means the committee established pursuant to Section 6.4.3 of the Operating Agreement dated April 1, 2001, as amended and restated, between Local Distribution Company and Transmission Owner.

1.47 Party or Parties shall have the meaning set forth in the introductory paragraph of this Agreement.

1.48 Person shall mean any individual, partnership, limited liability company, joint venture, corporation, trust, unincorporated organization, or governmental entity or any department or agency thereof.

1.49 Planned Outage shall mean action by (i) Local Distribution Company or Transmission Owner to take its equipment, facilities or systems out of service, partially or completely, to perform work on specific components that is scheduled in advance and has a predetermined start date and duration pursuant to the procedures set forth in Sections 3.10.1, 3.10.2, and 3.10.4. Planned Outage shall not include the construction of new facilities or system elements, the modification of existing facilities or system elements addressed in Article 9, which includes, but is not limited to, activities associated with the construction of third party facilities or with the modifications required to accommodate third party facilities.

1.50 Planning Committee means the committee established pursuant to Section 6.4.3 of the Operating Agreement dated April 1, 2001, as amended and restated, between Local Distribution Company and Transmission Owner.

1.51 Protective Relay is a device which detects abnormal power system conditions and, in response, initiates automatic control action

1.52 Protective Relay System is a group of Protective Relays and associated sensing devices and communications equipment that detects system abnormalities and performs automatic control action to mitigate or reduce adverse effects of such abnormalities.

1.53 Qualified Personnel shall mean individuals trained for their positions in accordance with Good Utility Practice.

1.54 Radial Asset shall mean facilities used for the distribution of electric energy through a single circuit (which may consist of any number of wires or cables) running to a substation or substations to serve Local Distribution Company's load customers.

1.55 RTO means Regional Transmission Organization.

1.56 Regulated Substance means any contaminant, hazardous waste, hazardous substance, hazardous constituent, or toxic substance, as defined in the Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA), 42 USC 9601 et seq, Resource Conservation and Recovery Act (RCRA), 42 USC 6901 et seq, Toxic Substances Control Act (TSCA), 15 USC 2601 et seq, The Michigan Natural Resources and Environmental Protection Act (MCLA 324.101 et seq); or any other similar statutes now or hereafter in effect.

1.57 Release shall mean, spill, leak, discharge, dispose of, pump, pour, emit, empty, inject, leach, dump, or allow to escape into or through the environment.

1.58 Revenue Quality Metering System shall mean a system which includes current and voltage instrument transformers, secondary wiring, test switches, meter transducer(s), meter and loss compensation as set forth in Article 5.

1.59 RTU – Remote Terminal Units shall mean a device connected by a communication system to one or more master computers with appropriate software placed at various locations to collect data and perform remote control. It may also perform intelligent autonomous control of electrical systems and report the results back to the master computer(s).

1.60 Security Coordinator shall mean a NERC-approved entity that provides the security assessment and emergency operations coordination for one or more Control Areas or transmission owners and which has operational authority under NERC standards over the Transmission Owner.

1.61 Steady-State Voltage shall mean the value of a voltage after all transients have decayed to a negligible value. The root-mean-square value in the steady-state does not vary with time.

1.62 Supervisory Control and Data Acquisition (SCADA) shall mean a system that provides data acquisition, supervisory control and alarm display and control from remote field locations to control centers.

1.63 System Modification Impact shall mean a physical change to an electrical system, element or facility subject to this Agreement that would require the reclassification of the same from a Distribution System equipment, element or facility to a Transmission System equipment, element or facility, or vice versa, consistent with the facility ownership classifications provided for in Section 3.2 hereof, Good Utility Practice and applicable NERC standards.

1.64 Transmission Owner shall mean the Michigan Electric Transmission Company, LLC and its successors and assigns.

1.65 Transmission Owner's Representative(s) shall be that person(s) identified as the point for contact for day-to-day operations of the Transmission System, identified in Section 2.3.

1.66 Transmission System shall mean, subject to and consistent with the provisions of Section 3.2 and Section 3.4 hereof, any equipment and facilities for the delivery of energy across a network that are not part of the Distribution System and the equipment and facilities owned, or that should be owned by the terms of this Agreement, by the Transmission Owner for the delivery of energy across a network.

1.67 Transmission System Operations Center(s) shall mean the electric Transmission System control center(s) that is/are responsible for monitoring and controlling the Transmission System in real time.

1.68 Unplanned Outage shall mean action by Local Distribution Company or Transmission Owner to take its equipment, facilities or systems out of service, partially or completely, due to an unanticipated failure, when such removal from service was not scheduled in accordance with Sections 3.10.1, 3.10.2, and 3.10.4. Such removal from service may be automatic such as by relay-action operating circuit breakers or by operator intervention. Momentary interruptions are excluded from the definition of Unplanned Outages. Unplanned Outages include Forced Outages as well as Extended Outages.

ARTICLE 2. Operational Requirements

2.1 Subject to the terms and conditions of this Agreement, Transmission Owner shall provide Local Distribution Company Interconnection Service for each Interconnection Point identified in Exhibit 1, from the Effective Date for the term of this Agreement.

2.2 The Interconnection Points between the Transmission System and Distribution System are listed in Exhibit 1. It shall be the Transmission Owner's responsibility to annually prepare an addendum to this exhibit that shows all new or modified interconnections. The original Exhibit 1 and all addendums shall be retained for future reference.

2.3 Local Distribution Company's Representatives and Transmission Owner's Representatives are listed in Exhibit 2, as may be modified from time to time by either Party, giving written notice of changes regarding its Representative(s) to the other Party.

2.4 Interconnection Standards

2.4.1 The Interconnection Point(s) shall be established and maintained in accordance with Good Utility Practice and the applicable NERC, Federal, State, OATT and ECAR standards and policies for Transmission Owner service to Local Distribution Company.

2.4.2 Reactive Power. Transmission Owner and Local Distribution Company recognize and agree that they have a mutual responsibility for maintaining voltage at the Interconnection Points. Transmission Owner is responsible for maintaining Transmission System voltage as listed in Sections 8.1 and 8.2 and reasonably compensating for reactive power losses resulting from transmission service. The Local Distribution Company is responsible for controlling Distribution System voltage and compensating for Distribution System reactive power losses and reactive power consumed by retail customers. The Local Distribution Company may use a combination of static and dynamic reactive resources at various locations around the Transmission Owner's system. The Local Distribution Company's and the Transmission Owner's SCADA systems shall be used to determine the net exchange of reactive power on a total

interconnections basis. For those distribution substations where there are no SCADA facilities in place the reactive flows shall be determined from SCADA data on the connecting lines in conjunction with computer load flow simulations. At load levels below 90% of peak the system should be designed such that the average power factor for the sum of all Interconnection Points is between 90% lagging and 90% leading ("peak" as used here shall refer to a current year's maximum MW load for the Local Distribution Company). For load levels above 90% of peak the power factor should be at 98% (lagging or leading), or better. If the power factor falls below this minimum the Planning Committee shall review available options and determine the best method of addressing any resulting system problems.

2.5 (a) The Local Distribution Company shall comply with Transmission Owner's reasonable operating requirements or switching procedures. The Local Distribution Company shall verbally notify the Transmission Owner if the Local Distribution Company is unable to comply with this Section at any time during the term of the Agreement.

(b) The Transmission Owner shall comply with Local Distribution Company's reasonable operating requirements or switching procedures. The Transmission Owner shall verbally notify the Local Distribution Company if the Transmission Owner is unable to comply with this Section at any time during the term of the Agreement.

2.6 Local Distribution Company shall comply with the requests, orders, directives and requirements of Transmission Owner in its role of implementing the directives of the Security Coordinator. Any such requests, orders, directives or requirements of Transmission Owner must be (a) issued in accordance with Good Utility Practice, (b) not unduly discriminatory, (c) otherwise in accordance with applicable tariffs or applicable federal, state or local laws, (d) in conformance with NERC operating procedures, and (e) reasonably necessary to maintain the integrity of the Transmission System.

2.7 Load Shedding

2.7.1 Local Distribution Company shall comply, as part of a Control Area program, with installation of automatic underfrequency load shedding equipment and maintain compliance with the standards set forth in NERC and ECAR operating standards and policies at Transmission Owner's expense.

2.7.2 The Transmission Owner may direct the Local Distribution Company to shed load to maintain the reliability and integrity of the Transmission System, in accordance with the OATT. The Transmission Owner and the Local Distribution Company will comply with MPSC directives and will

endeavor to minimize the impact on the Local Distribution Company customers.

2.8 Not a Reservation for Transmission Service

2.8.1 Local Distribution Company, or an Eligible Customer under the OATT, shall be responsible for making arrangements under the OATT for transmission and any ancillary services associated with the delivery of capacity and/or energy purchased or produced by the Local Distribution Company, which services shall not be provided under this Agreement.

2.8.2 Local Distribution Company and Transmission Owner make no guarantees to the other under this Agreement with respect to transmission service that is available under the Transmission Owner's OATT or any other tariff under which transmission service may be available in the region. Nothing in this Agreement shall constitute an express or implied representation or warranty with respect to the current or future availability of transmission service. Should the Parties enter into an arrangement under the OATT or another tariff, any terms in this Interconnection Agreement that may be in conflict with that tariff shall be subordinate to the terms of that tariff.

ARTICLE 3. Ownership, Conveyance, Operation and Maintenance

3.1 The Operating Committee shall develop specific methods and procedures with respect to Local Distribution Company's and Transmission Owner's systems covering at least, but not limited to, the following areas: safety, voltage control, outage planning and implementation, service restoration, emergency operations procedures, frequency controls, environmental matters, and maintenance planning and execution.

3.2 Facility Classification and Rights

3.2.1 Facility Classifications

3.2.1.1 As between the Parties, Local Distribution Company shall be the exclusive owner, operator and constructor of Distribution System equipment, elements, and facilities, and shall have the exclusive right to build, own, operate, and maintain: (i) all equipment, elements, and facilities operated below a Nominal Voltage of 120 kV; and (ii) all new Radial Assets operated at a Nominal Voltage at or above 120 kV.

3.2.1.2 As between the Parties, Transmission Owner is and shall be the exclusive owner, operator, and constructor of Transmission System equipment, elements and facilities.

3.2.1.3 As contemplated in Section 3.4.2, a System Modification Impact will require the reclassification of a facility. Either Party may identify a physical change to the electrical functioning of any equipment, element or facility subject to this Agreement that would require the reclassification of the same from a Distribution System equipment, element or facility to a Transmission System equipment, element or facility, or vice versa, consistent with the facility ownership classifications provided for in this Section 3.2, Good Utility Practice, and applicable NERC standards. Such identification shall be made via written notice to the other Party. The conveyance of the identified equipment, element or facility shall be accomplished under the procedures identified in Section 3.4. If the other Party disputes the applicability of reclassification of a particular equipment, element or facility, then the dispute resolution procedures in Article 25 shall apply.

3.2.2 Recordkeeping

3.2.2.1 Exhibit 5 has been omitted from this Agreement. Previously, this Exhibit reflected ownership changes and the Parties agree this Exhibit is unnecessary.

3.2.2.2 Wiring Diagrams (WDs) will be updated continuously in each Party's Drawing Management System (DMS) which is shared between the Parties and approved by both Parties at least annually when Exhibit 6 is updated to show changes in ownership. For purpose of this Section 3.12, such submission and approval of changes shall be in writing consistent with Section 11.1.

3.3 All operation and maintenance activities will be the financial responsibility of the owning Party. All operation and maintenance activities on Jointly Owned Assets will be under the direction and control of the Party that owns the greater percentage of the major equipment at that location. In the case where both Parties own an equal share the Local Distribution Company shall have such direction and control. The Parties' respective share of responsibility for the costs of all operation and maintenance activities on Jointly Owned Assets shall be the same percentage as the percentage of major equipment owned by the Party in that substation as set forth in Exhibit 6 and its subsequent addendums, provided that the minority owner's ownership interest exceeds 1%; if it does not, then the majority owner will be solely responsible for these operation and maintenance costs and corresponding capital replacements. All generation-related assets owned by the Local Distribution Company in a substation will be included as a part of the Local Distribution Company's assets in making this calculation. Responsibilities related to third-party owned generation-related assets will be split according to the nominal operating voltage at the point of connection of the generation circuit. At 120 kV and above the third-party generation-related assets

will be included as a part of the Transmission Owner's assets for purposes of making this calculation. Below 120 kV the third-party generation-related assets will be included as a part of the Local Distribution Company's assets for purposes of making this calculation. Major equipment shall be defined as main power transformers, 23 kV, 46 kV, 138 kV, and 345 kV circuit breakers, power system regulators and reclosers, and 46 kV and 138 kV capacitor banks. (Any three-phase installation of such equipment shall count as a single unit). Exhibit 6 will be updated with an addendum at least annually by the Transmission Owner and approved in writing by the Local Distribution Company to show all changes in equipment ownership in the joint substations. The original Exhibit 6 and all addendums will be retained for future reference. In those substations where each Party owns assets each Party shall be financially responsible for its appropriate share of station power energy usage.

3.4 Reclassification and Conveyance

3.4.1 The facility classifications provided for in Subsection 3.2.1 hereof shall govern the Parties' ownership of existing and future Distribution System facilities and Transmission System facilities, except as provided in Subsection 3.4.2.

3.4.2 Any System Modification Impact shall require a Party to convey ownership to the appropriate Party in accordance with the ownership classifications provided for in Section 3.2 and the terms of this Section 3.4. However, no such reclassification shall affect how the other Sections of this Agreement are applied until there is a change in ownership of the facilities involved and until any related changes are made to this Agreement and its exhibits, as may be required. Upon such a change in ownership, the Planning Committee shall revise any Exhibits hereto when needed to reflect the change in ownership.

3.4.3 A facility conveyed pursuant to Section 3.4.2 shall be priced at 1.18 times the seller's net plant value but in any case, shall not be less than zero dollars (i.e., no payment from seller to purchaser will occur as a result of net plant value being less than zero). As used herein, "net plant value" shall mean the asset's original cost depreciated according to the seller's accepted accounting method. In addition, should either Party plan to abandon or otherwise take out of service any facilities which could be of use as part of the other Party's system, it shall offer to convey to the other Party such facilities before they are taken out of service under the same pricing formula outlined above.

3.4.4 All types of conveyances discussed in this Section 3.4 shall be subject to the following conditions:

(a) The Planning Committee shall within 12 months of the Effective Date of this Agreement develop appropriate timeframes and procedures for

accomplishing such conveyances. For the avoidance of doubt, any previous agreements, understandings, or practices between the Parties on this subject matter that in any way conflict with the terms of this Agreement, including but not limited to anything stated in Planning Practice 6, are hereby abrogated and superseded by this Agreement.

(b) At least 12 months (or as close as feasible to 12 months) before implementing system modifications which would result in such a conveyance, the Party planning to do such modifications shall notify the other Party of such plans. The other Party, if it wishes, shall then have 2 months within which to propose an alternative modification which is consistent with Good Utility Practice, which would reduce or eliminate the need for conveyances, and which would cost the Party seeking to do the modifications no more than the originally proposed modification. If such an alternative is provided in a timely manner, the Party proposing to do the modification shall consider the alternative and shall not unreasonably refuse to pursue the alternative instead of the original proposal.

(c) Possible impediments to timely conveying the property in question (e.g., difficulty in getting release from the conveyor's indenture) shall be referred to the Administrative Committee. The Administrative Committee is authorized to modify the requirements of this Section with regard to such a specific proposed modification however it deems appropriate in light of the possible impediment and other circumstances.

3.5 Each Party shall operate any equipment that might reasonably be expected to have impact on the operations of the other Party in a safe and efficient manner and in accordance with all applicable federal, state, and local laws, NERC operating practices, and Good Utility Practice, and otherwise in accordance with the terms of this Agreement. Each Party shall comply with the reasonable requests, orders, directives and requirements of the other Party, which are authorized under this Agreement.

3.6 (a) Without limiting the generality of Section 3.5, Local Distribution Company shall own, operate, and maintain its Distribution System in a manner in accordance with Good Utility Practice to prevent degradation of voltage or services of the Transmission System. The Local Distribution Company shall be responsible for the costs to repair or replace the Distribution System and Local Distribution Company's Interconnection Equipment.

(b) Without limiting the generality of Section 3.5, Transmission Owner shall own, operate, and maintain its Transmission System in a manner in accordance with Good Utility Practice to prevent degradation of voltage or services of Local Distribution Company's Distribution System. The Transmission Owner shall be responsible for the costs to repair or replace the Transmission System and Transmission Owner's Interconnection Equipment.

(c) Without limiting the generality of Section 3.5, Local Distribution Company or Transmission Owner, as appropriate pursuant to Section 3.3 hereof, shall operate and maintain Jointly Owned Assets in a manner in accordance with Good Utility Practice to prevent degradation of voltage or services to either Party.

3.7 (a) Except during an Emergency, Local Distribution Company shall not, without prior Transmission Owner authorization, operate any Transmission Owner circuit, including transformer, line, or bus elements. Local Distribution Company shall retain the right to operate Transmission Owner equipment during an Emergency. When practical, prior to operation of such equipment, Local Distribution Company shall provide notice to the Transmission Owner. The Local Distribution Company shall also have the right to operate Transmission Owner substations that serve five or fewer customers to maintain the integrity of the Distribution System under the specific real time direction of the Transmission Owner. The Local Distribution Company shall not operate any Transmission System circuit if upon notice the Transmission Owner expressly refuses to grant permission to the Local Distribution Company. Within five (5) working days of such Emergency, Local Distribution Company shall provide written explanation of such Emergency to Transmission Owner.

(b) Except during an Emergency, Transmission Owner shall not, without prior Local Distribution Company authorization, operate any Local Distribution Company circuit, including transformer, line, or bus elements. Transmission Owner shall retain the right to operate Local Distribution Company equipment, during an Emergency for imminent personnel safety threat, to prevent damage to equipment or to maintain the integrity of the Transmission System. When practical, prior to operation of such equipment, Transmission Owner shall provide notice to Local Distribution Company. Transmission Owner shall not operate any Distribution System circuit if upon notice the Local Distribution Company expressly refuses to grant permission to the Transmission Owner. Within five (5) working days of such Emergency, Transmission Owner shall provide written explanation of such Emergency to Local Distribution Company.

(c) In an Emergency, joint facilities shall be operated by the Party able to first respond with Qualified Personnel.

3.8 Local Distribution Company and Transmission Owner shall design, install, test, calibrate, set, and maintain their respective Protective Relay equipment in accordance with Good Utility Practice, applicable federal, state, or local laws and this Agreement, as set forth in Article 6 hereof. In the case of jointly owned relaying equipment, the Party having direction and control pursuant to
Section 3.3 hereof shall design, install, calibrate, set, and maintain Protective Relay equipment in accordance with Good Utility Practice. Without limiting the generality of Section 3.6(c) above, costs for such work will be split between the

Companies on a predetermined ownership percentage basis as set forth in the then-current version of Exhibit 6, provided that the minority owner's ownership interest exceeds 1%; if it does not, then the majority owner will be solely responsible for these costs.

3.9 (a) If Transmission Owner reasonably determines that (i) any of Local Distribution Company's Interconnection Equipment fails to perform in a manner in accordance with Good Utility Practice or this Agreement, or (ii) Local Distribution Company has failed to perform proper testing or maintenance of its Interconnection Equipment in accordance with Good Utility Practice or this Agreement, Transmission Owner shall give Local Distribution Company written notice to take corrective action. Such written notice shall be provided by Transmission Owner to Local Distribution Company's Representative as soon as practicable upon such determination. If Local Distribution Company fails to initiate corrective action promptly, and in no event later than seven (7) days after the delivery of such notification, and if in Transmission Owner's reasonable judgment leaving Local Distribution Company's Distribution System connected with Transmission System would create an Emergency or Network Security Condition, Transmission Owner may, with as much prior verbal notification to Local Distribution Company and Distribution System Control as practicable, open only the Interconnection Point(s) needing corrective action connecting the Local Distribution Company and Transmission Owner until appropriate corrective actions have been completed by Local Distribution Company, as verified by Transmission Owner. Prior to taking such action, Transmission Owner shall give appropriate consideration to the needs of the Local Distribution Company's end-use customers. Transmission Owner's judgment with regard to an interruption of service under this paragraph shall be made in accordance with Good Utility Practice and subject to Section 3.1 hereto. In the case of such interruption, Transmission Owner shall immediately confer with Local Distribution Company regarding the conditions causing such interruption and its recommendation concerning timely correction thereof. Both Parties shall act promptly to correct the condition leading to such interruption and to restore the connection.

(b) If Local Distribution Company reasonably determines that (i) any of Transmission Owner's Interconnection Equipment fails to perform in a manner in accordance with Good Utility Practice or this Agreement, or (ii) Transmission Owner has failed to perform proper testing or maintenance of its Interconnection Equipment in accordance with Good Utility Practice or this Agreement, Local Distribution Company shall give Transmission Owner written notice to take corrective action. Such written notice shall be provided by Local Distribution Company to Transmission Owner's Representative as soon as practicable upon such determination. If Transmission Owner fails to initiate corrective action promptly, and in no event later than seven (7) days after the delivery of such notification, and if in Local Distribution Company's reasonable judgment leaving Transmission System connected with Local

Distribution Company's Distribution System would create an Emergency, Local Distribution Company may, with as much prior verbal notification to Transmission Owner and Distribution System Control as practicable, open only the Interconnection Point(s) needing corrective action connecting the Transmission Owner and Local Distribution Company until appropriate corrective actions have been completed by Transmission Owner, as verified by Local Distribution Company. Local Distribution Company's judgment with regard to an interruption of service under this paragraph shall be made in accordance with Good Utility Practice and subject to Section 3.1 hereto. In the case of such interruption, Local Distribution Company shall immediately confer with Transmission Owner regarding the conditions causing such interruption and its recommendation concerning timely correction thereof. Both Parties shall act promptly to correct the condition leading to such interruption and to restore the connection.

3.10 Outages

3.10.1 Outage Authority and Coordination. In accordance with Good Utility Practice, each Party may, in close cooperation with the other, remove from service its system elements that may impact the other Party's system as necessary to perform maintenance or testing or to replace installed equipment. Absent the existence of an Emergency, the Party scheduling a removal of a system element from service will schedule such removal on a date mutually acceptable to both Parties, in accordance with Good Utility Practice.

3.10.2 The Parties shall coordinate inspections, Planned Outages, and maintenance of their respective equipment, facilities and systems so as to minimize the impact on the availability, reliability and security of both Parties' systems and operations when the outage is likely to have a materially adverse impact on the other Party's system or the Local Distribution Company's end-use customers. Subject to the confidentiality provisions of Article 20, on or before October 1 of each year during the term hereof, the Parties shall exchange non-binding Planned Outage schedules for the following calendar year, which shall be developed and followed in accordance with Good Utility Practice, for the Distribution System and Transmission System. The Parties shall communicate the outage schedules as promptly as possible, provided that in no event shall such schedule be provided less than fifteen (15) days prior to a Planned Outage. The Parties shall keep each other updated regarding any changes to such schedules.

3.10.3 Unplanned Outages

3.10.3.1 Distribution System Unplanned Outage. In the event of an Unplanned Outage of a system element of the Distribution System adversely affecting the Transmission System, the Local

Distribution Company will act in accordance with Good Utility Practice to promptly restore that system element to service unless the Local Distribution Company obtains concurrence from the Transmission Owner that some deferral is reasonable, and this concurrence shall not be unreasonably withheld. The Local Distribution Company shall plan and maintain its Distribution System such that the average length of distribution system outages having a direct impact on the Transmission System shall not exceed 166 minutes per event on an annual basis. For any year in which the average outage duration exceeds this limit, the Local Distribution Company shall develop a plan to improve the outage restoration process and reduce outages and shall obtain the Transmission Owner's concurrence with this plan. Within forty-eight hours (48) of the beginning of any Unplanned Outage, the Local Distribution Company shall provide the Transmission Owner with a restoration plan.

3.10.3.2 Transmission System Unplanned Outage. In the event of an Unplanned Outage of a system element of the Transmission System adversely affecting the Local Distribution Company's Distribution System, the Transmission Owner will restore the system to normal as soon as possible unless the Transmission Owner obtains concurrence from the Local Distribution Owner that some deferral is reasonable, and this concurrence shall not be unreasonably withheld. The Transmission Owner shall plan and maintain its Transmission System such that the average length of Transmission System outages having a direct impact on customers of the Local Distribution Company shall not exceed 166 minutes on an annual basis. For any year in which the average outage duration exceeds this limit, the Transmission Owner shall develop a plan to improve the outage restoration process and reduce outages and shall obtain the Local Distribution Company's concurrence with this plan. Within forty-eight hours (48) of the beginning of any Unplanned Outage the Transmission Owner shall provide the Local Distribution Company with a restoration plan. For any 138 kV system outage it is expected that the system will be restored to its normal configuration within seven (7) days; for any 345 kV system outage it is expected that the system will be restored to its normal configuration within thirty (30) days. If it is expected that any Unplanned Outage will exceed these limits the Transmission Owner shall provide the Local Distribution Company with detailed information on measures being taken to minimize the outage time.

3.10.4 Planned Outages

3.10.4.1 Distribution System Planned Outage. In the event of a Planned Outage of a system element of the Distribution System adversely affecting the Transmission System, the Local Distribution Company will act in accordance with Good Utility Practice to promptly restore that system element to service in accordance with its schedule for the work that necessitated the Planned Outage.

3.10.4.2 Transmission System Planned Outage. The Transmission Owner shall review all Transmission System Planned Outages with the Local Distribution Company. In the event of a Planned Outage of a system element of the Transmission System adversely affecting the Local Distribution Company's Distribution System, the Transmission Owner will act in accordance with Good Utility Practice to promptly restore that system element to service in accordance with its schedule for the work that necessitated the Planned Outage.

3.11 The Parties shall use best efforts in accordance with Good Utility Practice to coordinate operations in the event of any Forced or Planned Outage that affects the other Party's system.

3.12 Black Start Plan Participation. In accordance with Good Utility Practice, Local Distribution Company agrees to participate in Transmission Owner's Black Start Plan for the Distribution System and the Transmission System, as well as any verification testing.

3.13 The Parties shall notify and make available in a timely manner, electric system modeling information necessary for the other Party to monitor, analyze, and protect its facilities in a real time environment, no less than 30 days prior to the energization of new or reconfigured network facilities.

ARTICLE 4. Supervisory Control and Data Acquisition, SCADA

4.1 If the Transmission Owner chooses to operate its own SCADA system, or to make modifications or additions to the existing system, the following terms and conditions of this Article 4 will apply.

4.2 Interconnection Points containing SCADA and communications equipment installed prior to April 1, 2001, shall be considered to satisfy the terms and conditions of this article. For those Interconnection Points that existed prior to April 1, 2001 that did not contain SCADA and communications equipment, and for new Interconnection Points installed after April 1, 2001 where SCADA and communications equipment is necessary for and requested by the Transmission Owner to perform monitoring, state estimation and contingency analysis, the Local Distribution Company shall install and operate such equipment at the

Transmission Owner's expense. Each Interconnection Point or other mutually agreeable location with SCADA and communications equipment shall have one dedicated communications path to the Local Distribution Company's control center for the RTU data. The cost of the dedicated communications path and general use station phone shall be shared on an equal basis. Additional data paths, SCADA equipment, and communications equipment requested, either emanating from the substation, the Local Distribution Company's control center, or the Transmission Owner's control center, will be at the expense of the requestor. This data and status information may be real time or with a time delay mutually acceptable to the Parties. The method of providing this data and control will be via an industry standard protocol such as Inter-Control Center Protocol (ICCP) or other method agreed to by the Parties. Such data may include, but not be limited to megawatts, megavars, voltage, amperes, device status, interchange schedule error, and communication system status.

4.3 The Transmission Owner reserves the right at its expense, to require, for new, or modified Local Distribution Company Interconnection Points, installation of a Transmission Owner's RTU or installation of a dual port RTU to provide data and control directly to the Transmission Owner within the Local Distribution Company's substation. The Local Distribution Company will assist in furnishing desired inputs for the Transmission Owner's RTU.

4.4 The operating metering system shall consist of instantaneous values of MW, MVAR, and voltage.

4.4.1 Values shall be inputted to a RTU or comparable communication device for communication with the Party having Control Area responsibility.

4.4.2 Transducers may utilize the voltage transformers and current transformer secondary circuits also utilized by the revenue metering equipment for a particular interconnection. In such case, the performance criteria listed in Exhibit 4 of the Agreement, Metering Specifications, for the voltage transformers and the current transformers, shall apply. Relaying class voltage transformers and or current transformers shall not be utilized unless mutually agreed between all the owners of the metering equipment and the Local Distribution Company.

4.4.3 Transducers shall have maximum 0.3% inaccuracy. Transducers shall be field calibrated as necessary but at least once every ten (10) years and documentation shall be retained showing the calibration results until next calibration.

4.4.4 Telemetry shall be maintained and calibrated such that overall inaccuracy of MW, MVAR, and voltage values is less than 1.0% of full scale.

4.5 To the extent new RTUs and associated communications equipment is to be installed, the Local Distribution Company shall install or facilitate installation of

the RTU and associated communications equipment as soon as practicable, provided that installation shall be accomplished within a time period of no more than 270 days following notice by Transmission Owner or prior to commissioning of any new Interconnection Points.

ARTICLE 5. Revenue Metering

5.1 Transmission Owner shall own, operate, test and maintain any metering equipment at the Interconnection Points, as required by this Article 5 not including any metering equipment owned by the Local Distribution Company for use in metering its end-use customers. Transmission Owner and Local Distribution Company agree that, as to all Interconnection Points in existence as of the Effective Date, no new or different metering equipment or arrangements shall be required. For existing Interconnection Points where low-side metering exists without loss compensation, the Parties will agree to adjust the metering data in such a manner to account for any real power losses between the location of the meter and the Interconnection Point. To the extent existing metering equipment is replaced and when new metering equipment is installed at Interconnection Points in existence as of the Effective Date, such replacements or installations shall meet the standards set in Section 5.2. Transmission Owner shall provide, install, own, operate, test, and maintain the new metering equipment located at the Interconnection Points.

5.2 The Revenue Quality Metering System shall consist of all instrument transformers (current and voltage), secondary wiring, test switches, and meter(s) required to determine the metering values for record for any given metering point

5.2.1 Metering shall be form 9, 3-element for 4-wire systems and form 5, 2-element for 3-wire systems.

5.2.2 Meters shall measure, at a minimum, megawatt hours and megavar hours and have bi-directional capability, where applicable. All measured values shall have individual outputs where applicable and a minimum 35-day interval data recording capability for each measured value.

5.2.3 Whenever feasible, any new metering facilities shall be located at the same physical location as the Interconnection Point. If it is not reasonable to have the metering facilities and the Interconnection Point at the same physical location, the metering data will be adjusted to account for real power losses between the location of the meter and the Interconnection Point.

5.2.4 Transmission Owner shall maintain records that demonstrate compliance with all meter tests and maintenance conducted in accordance with Good Utility Practice for the life of the Interconnection Point. Local Distribution Company shall have reasonable access to the records.

5.2.5 For installations where the metering is performed using loss compensation, the factory certified test results of the power transformer, if available, including load, no-load losses and calculated meter loss calculations, shall be recorded in a written record. Local Distribution Company shall have reasonable access to the records.

5.2.6 Transmission Owner shall maintain records of the factory certified test results, or the utility test shop test results, showing compliance of the meters with the applicable metering test standards.

5.2.7 Transmission Owner's Metering equipment shall be tested by Transmission Owner at its own expense not less than once every year, unless an extension of the testing cycle is agreed upon by the Parties. The accuracy of such metering equipment shall be maintained by Transmission Owner in accordance with applicable regulatory standards. At the request of either Party, special tests shall be made. If any special meter test discloses the metering device to be registering within acceptable limits of accuracy as specified herein, then the Party requesting such special meter test shall bear the expense thereof. Otherwise, the expense of such test shall be borne by the owner. Representatives of either Party shall be afforded opportunity to be present at all routine or special tests and upon occasions when any readings for purposes of settlements hereunder are taken from meters not producing an automatic record.

5.2.8 If, as a result of any test, any meter shall be found to be registering more than two (2) percent above or below one hundred (100) percent of accuracy, the account between the Parties hereto shall be corrected for a period equal to one-half of the elapsed time since the last prior test, according to the percentage of inaccuracy so found, except that if the meter shall have become defective or inaccurate at a reasonably ascertainable time since the last prior test of such meter, the correction shall extend back to such time. No meter shall be left in service if found to be more than two (2) percent above or below one hundred (100) percent of accuracy. Should metering equipment at any time fail to register, the energy delivered shall be determined from the best available data. All meters shall be kept under seal, such seals to be broken only when the meters are to be tested or adjusted.

5.2.9 Test switches shall be installed to allow independent testing and/or replacement of each meter and transducer utilizing the secondary circuit so as not to interrupt the operation of other devices utilizing the secondary circuit.

5.2.10 In substations where an RTU or other remote data collecting and telecommunication device is present, meters shall have form C, 3-wire

outputs with programmable values determined by the Transmission Owner for bi-directional MWHs and MVARs.

5.2.11 In the event an interconnection meter needs replacement or repair, a representative from Local Distribution Company shall be given a reasonable opportunity to be present during such repair or replacement.

ARTICLE 6. Protective Relaying and Control

6.1 Transmission Owner and the Local Distribution Company shall, in accordance with Good Utility Practice, coordinate, review and approve all new Protective Relaying equipment, including equipment settings, Protective Relay schemes, drawings, and functionality associated with each Interconnection Point. Protective Relaying equipment and schemes installed before the date of this agreement shall be considered to satisfy the terms and conditions of this Article 6. When existing equipment or schemes are replaced or when new equipment or schemes are installed per this Article 6 or in association with new Interconnection Points, then the terms and conditions of Article 6 shall apply. Each Party shall incur the expense for the work on its system.

6.2 To the extent that there is generation on the Distribution System which, in the reasonable judgment of either Party, may contribute material amounts of current to a fault on the Transmission System, the Local Distribution Company shall have and enforce standards to ensure the provision, installation and maintenance of relays, circuit breakers, and all other devices necessary to promptly remove any fault contribution of such generation to any short circuit occurring on the Transmission System and not otherwise isolated by the Transmission Owner equipment. Such standards will be included in the Local Distribution Company's connection requirements for generation. Transmission Owner and Local Distribution Company shall not be responsible for protection of such generation.

6.3 Transmission Owner shall own, operate, maintain and test those Protective Relay Systems that control their breakers or equivalent protective devices. Local Distribution Company shall own, operate, maintain, and test those Protective Relay Systems that control their breakers or equivalent protective devices governed by this Article 6. The Parties shall maintain, and, as necessary, upgrade their respective Protective Relay Systems and shall provide the other Party with access to available copies of operation and maintenance manuals and test records for all relay equipment upon request. The Transmission Owner will provide protective relay settings for the relays that control breakers or equivalent protective devices owned by the Local Distribution Company that also protect Transmission Owner's equipment. The Local Distribution Company will review and apply the settings.

6.4 The owner (Transmission Owner or Local Distribution Company) of the line will provide the relay communication channel necessary for line protection at its

expense. Owner will participate with other Party to test communication schemes upon request without charge.

6.5 The Parties shall test their respective relays associated with the Interconnection Points for correct calibration and operation. Parties shall coordinate design, installation, operation, and testing of Protective Relay schemes to insure that such relays operate in a coordinated manner so as to not cause adverse operating conditions on the other Party's system.

6.6 Local Distribution Company shall be responsible for Protective Relay maintenance, calibration and functional testing of relay systems that protect Local Distribution Company's equipment associated with the Interconnection Points and that protect Transmission Owner from Local Distribution Company's Interconnection Equipment to the extent such calibration and testing are in accordance with Good Utility Practice. All such maintenance and testing must be performed by Qualified Personnel selected by the Local Distribution Company. In addition, Local Distribution Company shall allow Transmission Owner to conduct visual inspection of all Protective Relays and associated maintenance records directly related to the interconnection. Related maintenance and operational records shall be maintained by the Local Distribution Company in accordance with Good Utility Practice. Upon completion of Protective Relay calibration testing and relay functional testing, Local Distribution Company shall make available copies of test reports and related records for review by Transmission Owner upon request. Local Distribution Company shall review test reports and document that Protective Relay System's tests and settings, as shown on such test reports, have been done in accordance with the equipment's specifications and Good Utility Practice.

6.7 (a) As Transmission Owner's system protection requirements change, Transmission Owner will upgrade its Protective Relaying System in accordance with Good Utility Practice. If these upgrades affect the serviceability and acceptability of the Protective Relaying Systems on the Interconnection Equipment which may be installed, owned, and operated by Local Distribution Company, the Local Distribution Company must upgrade its Protective Relay Systems at its expense (unless such modifications are required in association with the addition of generation to the system in which case Section 9.8 shall apply) as necessary to bring them into compatibility with that installed by Transmission Owner. Transmission Owner shall give Local Distribution Company notice of such upgrade as soon as practicable prior to the anticipated date of such upgrade. Any proposed protective system upgrades shall be reviewed by the Planning Committee in accordance with Section 7.3(vi) hereof.

(b) As Local Distribution Company's system protection requirements change, Local Distribution Company will upgrade its Protective Relaying System in accordance with Good Utility Practice. If these upgrades affect the serviceability and acceptability of the Protective Relaying Systems on the Interconnection Equipment which may be installed, owned, and operated by Transmission Owner,

Transmission Owner must upgrade its Protective Relaying Systems at its expense (unless such modifications are required in association with the addition of generation to the system in which case Section 9.8 shall apply) as necessary to bring them into compatibility with that installed by Local Distribution Company. Local Distribution Company shall give Transmission Owner notice of such upgrade as soon as practicable prior to the anticipated date of such upgrade. Any proposed protective system upgrades shall be reviewed by the Planning Committee in accordance with Section 7.3(vi) hereof.

6.8 Local Distribution Company shall provide necessary space to install or expand relay panels for substation system protection if requested by Transmission Owner. Any incremental costs required to accommodate such request shall be the responsibility of the Transmission Owner.

6.9 Transmission Owner shall provide the necessary space to install or expand relay panels for substation system protection if requested by Local Distribution Company. Any incremental costs required to accommodate such request shall be the responsibility of the Local Distribution Company.

6.10 Each Party will provide fault recorder, sequence of events, and relay information to the other party as needed and in a reasonable amount of time.

ARTICLE 7. Planning and Obligation to Serve

7.1 Adequacy Obligation. Subject to applicable regulatory approvals, including adherence to Least-Cost planning requirements and principles, adherence to applicable NERC, ECAR or other regional reliability council or successor organization's reliability requirements, and all other applicable operating reliability criteria and subject to the oversight and direction of the appropriate RTO or ISO, the Transmission Owner shall operate, maintain, plan and construct its Transmission System in accordance with Good Utility Practice in order to:

(i) deliver on a reliable basis the projected capacity and energy needs of all loads served by the Local Distribution Company's Distribution System and dependent upon the Transmission Owner's facilities for delivery of such energy to the Distribution System;

(ii) provide needed support to the Local Distribution Company where a transmission addition is the Least-Cost electric solution to an improvement need, including but not limited to, the reliability needs of the Local Distribution Company; and

(iii) deliver energy from both existing and new generating facilities connected to and dependent upon Transmission Owner's transmission of such energy

7.2 With regard to planning and construction of projects which affect Local Distribution Company and Local Distribution Company's load-serving area, the

Parties shall develop methods and procedures covering at least the following areas:

(i) coordination between short-term and long-term distribution and transmission planning;

(ii) developing and sharing computer simulation models needed to support Transmission Owner and Local Distribution Company planning activities;

(iii) coordination of permitting (including local and state approvals) and siting;

(iv) engineering and scheduling of new projects;

(v) construction and inspection standards;

(vi) information-sharing and priority-setting; and

(vii) health and safety issues.

7.3 With respect to Local Distribution Company's load-serving area, the Planning Committee, shall:

(i) implement the methods and procedures developed pursuant to Section 7.2;

(ii) review planning studies and reports regarding projects needed or proposed for the area in the next five (5) years, or as determined by the Planning Committee;

(iii) recommend additional studies or evaluation of plans;

(iv) follow Least-Cost planning principles in recommending specific projects;

(v) at least once every year, prepare a planning report which shall include in priority order a list of projects proposed by either Party for the next year, the estimated costs of such projects, and the timetable for such projects, including the in-service date; and

(vi) review proposed programmatic changes to the electric system, including protective system upgrades.

7.4 If the Parties agree upon the need for any such project, they shall cooperate and coordinate in seeking all necessary regulatory approvals for such project.

Transmission Owner shall coordinate and cooperate with Local Distribution

Company with respect to all communications and commitments to municipal, county, and state agencies involved in such project.

7.5 If Local Distribution Company proposes construction of a transmission project and Transmission Owner does not agree that such project is needed, Local Distribution Company shall have the right to petition an appropriate RTO, ISO or applicable regulatory agency for a declaratory ruling on whether the proposed project is needed pursuant to Transmission Owner's public-utility duty to plan and construct a reliable, adequate Transmission System.

7.6 Load Growth and Reliability Needs. Transmission Owner is obligated to plan and install any Transmission System components that may be necessary, as determined by a Least-Cost planning process in accordance with Section 7.1 and consistent with the established and consistently applied reliability criteria of the Parties, to accommodate Local Distribution Company's planned load growth and planned reliability improvements. Transmission Owner will construct new interconnections to Local Distribution Company facilities in accordance with Transmission Owner's planning criteria, other agreements in effect between the Parties, and Good Utility Practice. Transmission Owner shall bear the responsibility for such planning and installing in accordance with this Article 7. Transmission Owner's obligations under this Section 7.6 shall include the planning and installation of any new Interconnection Points that may be necessary to accommodate Local Distribution Company's planned load growth and planned reliability improvements. Recovery of the cost of such additions shall be in accordance with the OATT or other applicable tariff.

7.7 Local Distribution Company shall be the first point of contact and the wire-services provider for end-use customers.

7.8 Transmission Owner shall annually submit to Local Distribution Company, no later than February 1 of each year:

(i) Transmission Owner's plans covering the next five (5) years, or as determined by the Planning Committee, for installing Transmission System components that may be necessary to accommodate Local Distribution Company's planned load growth and reliability improvements as described in Section 7.6. Transmission Owner's plans shall include, but not be limited to, cost estimates and installation schedules for Transmission System components, and shall provide specific detail sufficient to allow Local Distribution Company to compare Transmission Owner's plans with Local Distribution Company's in-service requirements to meet its planned load growth and reliability needs.

(ii) A description of any changes to the Local Distribution Company's Distribution System that may be needed to accommodate

Transmission Owner's plans set forth in Section 7.8(i) will be requested by the Transmission Owner.

(iii) Projected voltage levels under Normal System Conditions and Transmission Owner's FERC 715 Planning criteria conditions at anticipated annual peak load and 80% of anticipated annual peak load for each Interconnection Point with planned additions for the next five (5) years, or as determined by the Planning Committee.

7.9 Local Distribution Company shall annually submit to Transmission Owner:

(a) no later than December 1 of each year, the most recent actual summer and winter demands in megawatts (MW) and megavars (MVAR) for all Interconnection Points connected to the Transmission System at the time of the Transmission Owner's most recent seasonal system peaks (Transmission Owner must provide the Local Distribution Company the day and hour of such peak no later than September 1); and

(b) no later than February 1 of each year:

(i) annual peak demand forecasts in MW for each Local Distribution Company Interconnection Point to the Transmission System for the next five (5) years, or as determined by the Planning Committee, together with corresponding projected power factors; and

(ii) planned facility (new Interconnection Points) connections to the Transmission System for the next five (5) years, or as determined by the Planning Committee.

ARTICLE 8. Transmission Service Level

8.1 Subject to applicable regulatory approvals, including adherence to Least-Cost planning requirements and principles, adherence to applicable NERC, ECAR or other regional reliability council or successor organization's reliability requirements, and all other applicable operating reliability criteria and subject to the oversight and direction of the appropriate RTO or ISO, the Transmission Owner shall operate, maintain, plan and construct its Transmission System in accordance with Good Utility Practice to provide the following service levels:

(i) A minimum Steady-State Voltage of 0.97 Per Unit (PU) at all Interconnection Points with Local Distribution Company with all influential Transmission Owner facilities in service (no contingency conditions);

(ii) A minimum Steady-State Voltage of 0.92 PU at all Interconnection Points with the Local Distribution Company influenced by one or more Transmission Owner facilities out of service (contingency conditions);

(iii) A maximum Steady-State Voltage of 1.05 PU at all Interconnection Points with the Local Distribution Company during all operating conditions;

(iv) An adequate Transmission System that shall not load Local Distribution Company facilities above normal ratings during peak load conditions with all influential Transmission Owner facilities in service (no contingency conditions);

(v) An adequate Transmission System that shall not load Local Distribution Company facilities above emergency ratings during peak load conditions with one or more influential Transmission Owner facilities out of service (contingency conditions);

(vi) On a three-year rolling average, experience no more than 0.357 Momentary Outage Events per 138 kV line protective zone (system average) and 0.743 Momentary Outage Events per 345 kV line protective zone (system average) per year. As used in this Article 8 the term “year” shall mean calendar year; and the term “line protective zone” is illustrated and defined as follows: Any given electrical fault on a transmission line will trip specific circuit breakers in a normally functioning system. All of the possible line fault locations that will trip these specific circuit breakers constitute the same line protective zone. Physically, a line protective zone consists of the conductors located between the current transformers that provide sensing to trip the circuit breakers for a line fault;

(vii) Experience no more than three (3) Momentary Outage Events on any given 138 kV line protective zone and two (2) Momentary Outage Events on any given 345 kV line protective zone per year;

(viii) On a three-year rolling average, experience no more than 0.21 Unplanned Outages per 138 kV line protective zone (system average) and 0.18 Unplanned Outages per 345 kV line protective zone (system average) per year;

(ix) Experience no more than four (4) Unplanned Outages on any given 138 kV line protective zone and three (3) Unplanned Outages on any given 345 kV line protective zone per year;

(x) Should the Transmission Owner fail to meet any of the requirements of Section 8.1(vi) or 8.1(viii) by more than 10% two years in a row, the Transmission Owner shall pay, as liquidated damages and not as a penalty, to the Local Distribution Company, an amount equal to one half of one percent (0.5%) of the annual revenue paid by the Local Distribution Company under the applicable transmission tariff; such liquidated damages amount shall be based upon the revenue received

in the second year of such failure. Such liquidated damages amount shall be increased by one half of a percent (0.5%) for each additional 10% by which the Transmission Owner fails to meet the any of the given outage targets, up to a maximum of 4.0% of the annual revenue. Outage events affecting 15% or more of transmission line protective zones within a 24-hour period will not be counted toward the requirements of Section 8.1.

If transmission service does not meet the requirements of this Article 8, Transmission Owner shall present an action plan acceptable to the Local Distribution Company within sixty (60) days of non-compliance of this Article 8 to restore transmission service to the minimum standards as described in this Article 8 in a timely manner. Should the Transmission Owner fail to correct the deficiency(s) within one year of notification from the Local Distribution Company, the Local Distribution Company shall have the right to take corrective action at the Transmission Owner's expense. The Local Distribution Company shall defer taking such actions for corrective measures normally requiring longer than one year to complete, provided the Transmission Owner is diligently pursuing such measures.

8.2 Should the Michigan Public Service Commission (MPSC) adopt service quality standards that the Local Distribution Company must meet that are more stringent than current historical performance; and should the transmission service level provided by the Transmission Owner directly or indirectly influence the Local Distribution Company's ability to meet such standards, the Local Distribution Company will promptly notify the Transmission Owner of such proposal and the Transmission Owner shall have an opportunity to participate either as a party or in cooperation with the Distribution Company, in any related MPSC hearings or proceedings. Subject to the foregoing and to any required approval by FERC, the Transmission Owner shall be responsible for meeting its proportional share of the adopted service quality standard and for any penalties that might be
assessed if the standards are not met.

8.3 Transmission Owner and the Local Distribution Company acknowledge that the Special Manufacturing Contracts in existence at the time of the original execution of the 2001 Amendment and Restatement of the Distribution-Transmission Interconnection Agreement and previously listed under this Exhibit 3 are no longer in effect or no longer have clauses with compensable disruptions/interruptions associated with them. As such, the Parties have agreed to omit Exhibit 3.

ARTICLE 9. New Construction and Modification

9.1 Subject to this Article 9, Transmission Owner may construct additional Transmission System elements or modify the existing Transmission System and Local Distribution Company may construct additional Distribution System

elements or modify the existing Distribution System. All such modifications and construction provided for herein, shall be conducted in accordance with Good Utility Practice and all applicable NERC and ECAR Standards. The Party that modifies the system elements or constructs new system elements is obligated to maintain the transmission, distribution and communications capabilities of the other Party in accordance with Good Utility Practice to avoid or minimize any adverse impact on the other Party. The Parties shall look to the operating history of the Local Distribution Company in the relevant geographic area prior to the Effective Date of this Agreement, where available, in determining what constitutes Good Utility Practice.

9.2 Notwithstanding the foregoing, no modifications to or new construction of facilities or access thereto, including but not limited to rights-of-way, fences, and gates, shall be made by either Party which might reasonably be expected to have a material effect upon the other Party with respect to operations or performance under this Agreement, without providing the other Party with sufficient information regarding the work prior to commencement to enable such Party to evaluate the impact of the proposed work on its operations. The information provided must be of sufficient detail to satisfy reasonable Transmission Owner or Local Distribution Company review and operational requirements. Each Party shall use reasonable efforts to minimize any adverse impact on the other Party.

9.3 If any Party intends to install any new facilities, equipment, systems, or circuits or any modifications to existing or future facilities, equipment, systems or circuits that could reasonably be expected to have a material effect upon the operation of the other Party, the Party desiring to perform said work shall, in addition to the requirements of Section 9.2, provide the other Party with drawings, plans, specifications and other necessary documentation for review at least 60 days prior to the start of the construction of any such installation. This notice period shall not apply to modifications or new installations made to resolve or prevent pending Emergency or Network Security Conditions.

9.4 The Party reviewing any drawings, plans, specifications, or other necessary documentation for review shall promptly review the same and provide any comments to the performing Party no later than 30 days prior to the start of the construction of any installation. Unless system modifications are required in association with the addition of generation to the system (in which case
Section 9.8 hereof shall apply) all such reviews shall be performed at no cost to either Party. The performing Party shall incorporate all requested modifications to the extent required in accordance with Good Utility Practice and compliance with this Agreement.

9.5 Within 180 days following placing in-service of any modification or construction subject to this Article 9, the Party initiating the work shall provide “as built” drawings, plans and related technical data to the other Party. Approval or review of any document referenced herein shall not relieve the initiating Party of its responsibility for the design or construction of any proposed facility, nor shall it

subject the other Party to any liability, except with respect to the confidentiality provisions of Article 20.

9.6 Each Party shall, at its own expense, have the right to inspect or observe all maintenance activities, equipment tests, installation work, construction work, and modification work to the facilities of the other Party that could have a material effect upon the facilities or operations of the first Party.

9.7 Construction and installation of any facility shall meet all or exceed all environmental permitting requirements, reviews or approvals as required by federal, state or local law prior to the installation of such facilities. The Parties agree to coordinate environmental permitting related activities such as site review for regulated resources, permit application and project oversight (e.g. monitoring as applicable).

9.8 Whenever system modifications are required to connect generating facilities to either the Local Distribution Company's or the Transmission Owner's system it is expected that the party installing the generating facilities will normally be responsible for much or all of the associated costs. The Parties agree to cooperate in sharing information regarding such projects and to individually make arrangements with the party adding the generation to obtain payment of all related costs as appropriate.

ARTICLE 10. Access to Facilities

10.1 The Parties hereby agree to provide each other reasonable access to their respective property as may be necessary and appropriate to enable each Party to operate and maintain its respective facilities and equipment on such property. Such right of access shall be provided in a manner so as not to unreasonably interfere with either Party's ongoing business operations, rights, and obligations.

10.2 Each Party shall provide the other Party keys, access codes or other access methods necessary to enter the other Party's facilities to exercise rights under this Agreement. Access shall only be granted to Qualified Personnel.

ARTICLE 11. Notifications and Reporting

11.1 Unless otherwise provided, any notice required to be given by either Party to the other Party in connection with this Agreement shall be given in writing:
(a) personally; (b) by facsimile transmission (if sender thereafter sends such notice to recipient by any of the other methods provided in this Section 11.1; (c) by registered or certified U.S. mail, return receipt requested, postage prepaid; or (d) by reputable overnight carrier, with acknowledged receipt of delivery; or (e) any other method mutually agreed by the Parties in writing. Notice shall be deemed given on the date of receipt personally. Notice sent by facsimile shall be deemed given on the date the transmission is confirmed by sender's facsimile machine, so long as the facsimile is sent on a business day during normal business hours of the recipient. Otherwise, the notice shall be deemed given on

the next succeeding business day. Notice provided by mail or overnight courier shall be deemed given at the date of acceptance or refusal of acceptance shown on such receipt.

11.2 Notice to the Transmission Owner shall be to the Transmission Owner's Representative, at the addresses identified in Exhibit 2. Notice to the Local Distribution Company shall be to the Local Distribution Company's Representative, at the addresses identified in Exhibit 2.

11.3 Each Party shall provide prompt notice describing the nature and extent of the condition, the impact on operations, and all corrective action, to the other Party of any Emergency or Network Security Condition which may be reasonably anticipated to affect the other Party's equipment, facilities, or operations. Either Party may take reasonable and necessary action, both on its own and the other Party's system, equipment, and facilities, to prevent, avoid or mitigate injury, danger, damage or loss to its own equipment and facilities, or to expedite restoration of service; provided however, that the Party taking such action shall give the other Party prior notice, if at all possible, before taking any action on the other Party's system, equipment, or facilities.

11.4 In the event of an Emergency or Network Security Condition contemplated by Section 11.3, each Party shall provide the other with such information, documents, and data necessary for operation of the Transmission System and Distribution System, including, without limitation, such information which is to be supplied to any Governmental Authority, NERC, ECAR, or Transmission System Operations Center or Distribution System Control Center.

11.5 In order to continue interconnection of the Distribution System and Transmission System, each Party shall promptly provide the other Party with all relevant information, documents, or data regarding the Distribution System and the Transmission System that would be expected to affect the Distribution System or Transmission System, and which is reasonably requested by NERC, ECAR, or any Governmental Authority.

11.6 For routine maintenance and inspection activities on either Parties system that will require major equipment or system outages, and could impact the other Party's system, the Party performing the same shall provide the other Party with not less than seventy-two (72) hours prior notice, if practicable; provided that the provisions of Section 3.9 remain applicable to the outages, and said notice is in addition to, and does not substitute for, the requirements of Section 3.9 (maintenance and inspection activities in generating plant substations require 20 working days notification).

11.7 Transmission Owner shall notify Local Distribution Company prior to entering Local Distribution Company's facilities for routine measurements, inspections and meter reads in accordance with the requirements of Section 11.6. Local Distribution Company shall notify Transmission Owner prior to entering

Transmission Owner's facilities, including switchyards, for routine maintenance, operations, measurements, inspections and meter reads, in accordance with the requirements of Section 11.6.

11.8 Each Party shall provide prompt verbal notice to the other Party of any system alarm that applies to the other Party's equipment, unless the system alarm is automatically sent to the other Party.

11.9 Each Party shall provide a report or a copy of the data from a system events recorder, SCADA system sequence of events or digital fault recorder that applies to the other Party's equipment.

11.10 Each Party agrees to immediately notify the other Party verbally, and then in writing, of any labor dispute or anticipated labor dispute of which its management has actual Knowledge that might reasonably be expected to affect the operations of the other Party with respect to this Agreement.

ARTICLE 12. Safety

12.1 Each Party agrees that all work performed by either Party that may reasonably be expected to affect the other Party shall be performed in accordance with Good Utility Practice and all applicable laws, regulations, safety standards, practices and procedures and other requirements pertaining to the safety of Persons or property, (including, but not limited to those of the Occupational Safety and Health Administration, the National Electrical Safety Code and those developed or accepted by Transmission Owner and Local Distribution Company for use on their respective systems) when entering or working in the other Party's property or facilities or switching area. A Party performing work within the boundaries of the other Party's facilities must abide by the safety rules applicable to the site.

12.2 Each Party shall be solely responsible for the safety and supervision of its own employees, agents, representatives, and subcontractors.

12.3 Transmission Owner shall immediately report any injuries that occur while working on the Local Distribution Company's property or facilities or switching area to appropriate agencies and the Local Distribution Company's Site Representative. Local Distribution Company shall immediately report any injuries that occur while working on the Transmission Owner's property or facilities or switching area to appropriate agencies and the Transmission Owner's Site Representative. Each Party will provide the other with its clearing/tagging/lockout procedures. For clearances requested or initiated by the Local Distribution Company on the Local Distribution Company's equipment that utilizes the Transmission Owner's equipment as an isolation device, Local Distribution Company procedures shall govern. For clearances requested or initiated by the Transmission Owner on the Transmission Owner's equipment that utilizes the Local Distribution Company's equipment as an isolation device,

Transmission Owner procedures shall govern. Under no circumstances shall either Party remove the other Party's protective tags without proper authorization.

ARTICLE 13. Environmental Compliance and Procedures

13.1 Release Prevention and Response. Each Party shall notify the other Party, verbally within 24 hours upon discovery of any Release of any Regulated Substance caused by the Party's operations or equipment that impacts the property or facilities of the other Party, or which may migrate to, or adversely impact the property, facilities or operations of the other Party and shall promptly furnish to the other Party copies of any reports filed with any governmental agencies addressing such events. Such verbal notification shall be followed by written notification within five (5) days. The Party responsible for the Release of any Regulated Substance on the property or facilities of the other Party, or which may migrate to, or adversely impact the property, facilities or operations of the other Party shall be responsible for: (1) the cost and completion of reasonable remediation or abatement activity for that Release, and; (2) required notifications to governmental agencies and submitting of all reports or filings required by environmental laws for that Release. Advance written notification (except in Emergency situations, in which verbal, followed by written notification, shall be provided as soon as practicable) shall be provided to the other Party by the Party responsible for any remediation or abatement activity on the property or facilities of the other Party, or which may adversely impact the property, facilities, or operations of the other Party. Except in Emergency situations such remediation or abatement activity shall be performed only with the consent of the Party owning the affected property or facilities.

13.2 The Parties agree to coordinate, to the extent necessary, the preparation of site plans, reports, environmental permits, clearances and notifications required by federal and state law or regulation, including but not limited to Spill Prevention, Control and Countermeasures (SPCC), Storm Water Pollution Prevention Plans (SWPP), Act 451 Part 31 Part 5 Rules, CERCLA, EPCRA, TSCA, soil erosion and sedimentation control plans (SESC) or activities, wetland or other water-related permits, threatened or endangered species reviews or management and archeological clearances or notifications required by any regulatory agency or competent jurisdiction. Notification of permits applied for and/or received will occur in a timeframe manner suitable to the interests of both Parties.

ARTICLE 14. Billings and Payment

14.1 Any invoices payable under this Agreement shall be provided to the other Party under this Agreement during the preceding month. Invoices shall be prepared within a reasonable time after the first day of each month. Each invoice shall delineate the month in which services were provided, shall fully describe the services rendered and shall be itemized to reflect the services performed or provided. The invoice shall be paid within twenty (20) days of the invoice date, or the first business day thereafter if the payment date falls on other than a

business day. All payments shall be made in immediately available funds payable to the other Party, or by wire transfer to a bank of the Party being paid, provided that payments expressly required by this Agreement to be mailed shall be mailed in accordance with Section 14.2.

14.2 Any payments required to be made by Local Distribution Company under this Agreement shall be made to Transmission Owner at the following address:

Michigan Electric Transmission Company, LLC
P.O. Box 673971
Detroit, MI 48267-3971

Any payments required to be made by Transmission Owner under this Agreement shall be made to Local Distribution Company at the following address:

Consumers Energy Company
One Energy Plaza
Jackson, MI 49201
Attention: Treasurer

14.3 The rate of interest on any amount not paid when due shall be equal to the Interest Rate in effect at the time such amount became due. Interest on delinquent amounts shall be calculated from the due date of the invoice to the date of the payment. When payments are made by mail, invoices shall be considered as having been paid on the date of receipt by the other Party. Nothing contained in this article is intended to limit either Party's remedies under Article 21 of this Agreement.

14.4 Payment of an invoice shall not relieve the paying Party from any responsibilities or obligations it has under this Agreement, nor shall such payment constitute a waiver of any claims arising hereunder.

14.5 If all or part of any bill is disputed by a Party, that Party shall promptly pay the amount that is not disputed and provide the other Party a reasonably detailed written explanation of the basis for the dispute pursuant to Article 26. While the dispute is being resolved, the Parties shall continue to provide services and pay all invoiced amounts not in dispute. Following resolution of the dispute, the prevailing Party shall be entitled to receive the disputed amount, as finally determined to be payable, along with interest accrued at the Interest Rate through the date on which payment is made, within ten (10) business days of such resolution.

14.6 Subject to the Confidentiality provisions of Article 20, within two (2) years following a calendar year, during normal business hours, Local Distribution Company and Transmission Owner shall have the right to audit each other's accounts and records pertaining to transactions under this Agreement that occurred during such calendar year at the offices where such accounts and records are maintained; provided that the audit shall be limited to those portions

of such accounts and records that reasonably relate to the services provided to the other Party under this Agreement for said calendar year. The Party being audited shall be entitled to review the audit report and any supporting materials. To the extent that audited information includes Confidential Information, the auditing Party shall keep all such information confidential pursuant to Article 20.

14.7 Neither Party shall be responsible for the other Party's costs of collecting amounts due under this Agreement, including attorney fees and expenses and the expenses of arbitration.

ARTICLE 15. Applicable Regulations and Interpretation

15.1 Each Party's performance under this Agreement is subject to the condition that all requisite governmental and regulatory approvals for such performance are obtained in form and substance satisfactory to the other Party in its reasonable judgment. Each Party shall exercise Due Diligence and shall act in good faith to secure all appropriate approvals in a timely fashion.

15.2 This Agreement and all rights, obligations, and performances of the Parties hereunder, are subject to present or future state or federal laws, regulations, or orders properly issued by state or federal bodies having jurisdiction. When not in conflict with or pre-empted by federal law, this Agreement shall be interpreted pursuant to the laws of the State of Michigan, exclusive of its conflicts of law principles.

ARTICLE 16. Force Majeure

16.1 An event of Force Majeure means any act of God, labor disturbance, act of the public enemy, war, insurrection, riot, fire, storm or flood, explosion, breakage or accident to machinery or equipment, any curtailment, order, regulation, or restriction imposed by governmental military or lawfully established civilian authorities, or any other cause beyond a Party's reasonable control. A Force Majeure event does not include an act of negligence or intentional wrongdoing.

16.2 If either Party is rendered unable, wholly or in part, by Force Majeure, to carry out its obligations under this Agreement, then, during the continuance of such inability, the obligation of such Party shall be suspended except that Transmission Owner's and Local Distribution Company's obligation under Section 16.3 of this Agreement to provide protection shall not be suspended. The Party relying on Force Majeure shall give written notice of Force Majeure to the other Party as soon as practicable after such event occurs. Upon the conclusion of Force Majeure, the Party heretofore relying on Force Majeure shall, with all reasonable dispatch, take all necessary steps to resume the obligation previously suspended.

16.3 Any Party's obligation to make payments already owing shall not be suspended by Force Majeure.

ARTICLE 17. Indemnification and Limitation on Liability

17.1 Each Party shall at all times assume all liability for, and shall indemnify and save the other Party harmless from any and all damages, losses, claims, demands, suits, recoveries, costs, legal fees, expenses for injury to or death of any Person or Persons whomsoever, or for any loss, destruction of or damage to any property of third persons, firms, corporations or other entities that occurs on its own system and that arises out of or results from, either directly or indirectly, its own facilities or facilities controlled by it, unless caused by the sole negligence, or intentional wrongdoing, of the other Party.

17.2 NEITHER PARTY SHALL BE LIABLE TO THE OTHER FOR ANY SPECIAL, INCIDENTAL, EXEMPLARY, PUNITITIVE OR CONSEQUENTIAL DAMAGES SUCH AS, BUT NOT LIMITED TO, LOST PROFITS, REVENUE OR GOOD WILL, INTEREST, LOSS BY REASON OF SHUTDOWN OR NON-OPERATION OF EQUIPMENT OR MACHINERY, INCREASED EXPENSE OF OPERATION OF EQUIPMENT OR MACHINERY, COST OF PURCHASED OR REPLACEMENT POWER OR SERVICES OR CLAIMS BY CUSTOMERS, WHETHER SUCH LOSS IS BASED ON CONTRACT, WARRANTY, NEGLIGENCE, STRICT LIABILITY OR OTHERWISE.

ARTICLE 18. Insurance

18.1 The Parties agree to maintain, at their own cost and expense, the following insurance coverages for the life of this Agreement in the manner and amounts, at a minimum, as set forth below:

(a) Workers' Compensation Insurance in accordance with all applicable State, Federal, and Maritime Law.

(b) Employer's Liability insurance in the amount of $1,000,000 per accident.

(c) Commercial General Liability or Excess Liability Insurance in the amount of $25,000,000 per occurrence.

(d) Automobile Liability Insurance for all owned, non-owned, and hired vehicles in the amount of $5,000,000 each accident.

18.2 A Party may, at its option, [A] be an approved self-insurer by the State of Michigan for the insurances required in 1.(a) and (d); and [B] maintain such deductibles and/or retentions under the insurance required in 1.(b) and (c) as is maintained by other similarly situated companies engaged in a similar business. The Parties agree that all amounts of self-insurance, retentions and/or deductibles are the responsibility of, and shall be borne by, the Party whom makes such an election.

18.3 Within fifteen (15) days of the Effective Date and thereafter when requested, in writing, but not more than once every 12 months, during the term of this

Agreement (including any extensions) each Party shall provide to the other Party properly executed and current certificates of insurance or evidence of approved self-insurance status with respect to all insurance required to be maintained by such Party under this Agreement. Certificates of insurance shall provide the following information:

(a) Name of insurance company, policy number and expiration date.

(b) The coverage maintained and the limits on each, including the amount of deductibles or retentions, which shall be for the account of the Party maintaining such policy.

(c) The insurance company shall endeavor to provide thirty (30) days prior written notice of cancellation to the certificate holder.

ARTICLE 19. Several Obligations

19.1 Except where specifically stated in this Agreement to be otherwise, the duties, obligations and liabilities of the Parties are intended to be several and not joint or collective. Nothing contained in this Agreement shall ever be construed to create an association, trust, partnership, or joint venture or to impose a trust or partnership duty, obligation or liability or agency relationship on or with regard to either Party. Each Party shall be individually and severally liable for its own obligations under this Agreement.

ARTICLE 20. Confidentiality

20.1 (a) "Confidential Information" shall mean any confidential, proprietary or trade secret information of a plan, specification, pattern, procedure, design, device, list concept, policy or compilation relating to the present or planned business of a Party, which is designated in good faith as Confidential by the Party supplying the information, whether conveyed orally, electronically, in writing, through inspection or otherwise. Confidential Information shall include, without limitation, all information relating to a Party's technology, research and development, business affairs, and pricing, customer-specific load data that constitutes a trade secret, and any information supplied by either of the Parties to the other prior to the execution of this Agreement.

(b) General. Each Party will hold in confidence any and all Confidential Information unless (1) compelled to disclose such information by judicial or administrative process or other provisions of law or as otherwise provided for in this Agreement, or (2) to meet obligations imposed by FERC or by a state or other federal entity or by membership in NERC or ECAR (including other Transmission Owners). Information required to be disclosed under (b)(1) or (b)(2) above, does not, by itself, cause any information provided by Local Distribution Company to Transmission Owner to lose its confidentiality. To the extent it is necessary for either Party to release or disclose such information to a third party in order to perform that Party's obligations herein,

such Party shall advise said third party of the confidentiality provisions of this Agreement and use its best efforts to require said third party to agree in writing to comply with such provisions. Each party will develop and file with FERC standards of conduct relating to the sharing of a market-related Confidential Information with and by their employees.

(c) Term: During the term of this Agreement, and for a period of three (3) years after the expiration or termination of this Agreement, except as otherwise provided in this Article 20, each Party shall hold in confidence and shall not disclose to any Person Confidential Information.

(d) Standard of Care: Each Party shall use at least the same standard of care to protect Confidential Information it receives as that it uses to protect its own Confidential Information from unauthorized disclosure, publication or dissemination.

20.2 Scope: Confidential Information shall not include information that the receiving Party can demonstrate: (1) is generally available to the public other than as a result of disclosure by the receiving Party; (2) was in the lawful possession of the receiving Party on a non-confidential basis prior to receiving it from the disclosing Party; or (3) was supplied to the receiving Party without restriction by a third party, who, to the Knowledge of the receiving Party, after due inquiry was under no obligation to the disclosing Party to keep such information confidential; (4) was independently developed by the receiving Party without reference to Confidential Information of the disclosing Party; (5) is, or becomes, publicly known, through no wrongful act or omission of the receiving Party or breach of this Agreement; or (6) is required, in accordance with Section 20.1(b) of this Agreement, to be disclosed by any federal or state government or agency or is otherwise required to be disclosed by law or subpoena, or is necessary in any legal proceeding establishing rights and obligations under this Agreement. Information designated as Confidential Information will no longer be deemed confidential if the Party that designated the information as confidential notifies the other Party that it no longer is confidential.

20.3 Order of Disclosure. If a court or a government agency or entity with the right power, and apparent authority to do so requests or requires either Party, by subpoena, oral deposition, interrogatories, requests for production of documents, administrative order, or otherwise, to disclose Confidential Information, that Party shall provide the other Party with prompt notice of such request(s) or requirement(s) so that the other Party may seek an appropriate protective order or waive compliance with the terms of this Agreement. The notifying Party shall have no obligation to oppose or object to any attempt to obtain such production except to the extent requested to do so by the disclosing Party and at the disclosing Party’s expense. If either Party desires to object or oppose such production, it must do so at its own expense. The disclosing Party may request a protective order to prevent any Confidential Information from being made public. Notwithstanding the absence of a protective order or waiver, the Party may

disclose such Confidential Information which, in the opinion of its counsel, the Party is legally compelled to disclose. Each Party will use reasonable effort to obtain reliable assurance that confidential treatment will be accorded any Confidential Information so furnished.

20.4 Use of Information or Documentation. Each Party may utilize information or documentation furnished by the disclosing Party and subject to Section 20.1 in any proceeding under Article 26 or in an administrative agency or court of competent jurisdiction addressing any dispute arising under this Agreement, subject to a confidentiality agreement with all participants (including, if applicable, any arbitrator) or a protective order.

20.5 Remedies Regarding Confidentiality. The Parties agree that monetary damages by themselves will be inadequate to compensate a Party for the other Party's breach of its obligations under this article. Each Party accordingly agrees that the other Party is entitled to equitable relief, by way of injunction or otherwise, if it breaches or threatens to breach its obligations under this article.

ARTICLE 21. Breach, Default and Remedies

21.1 General. A breach of this Agreement ("Breach") shall occur upon the failure by a Party to perform or observe a material term or condition of this Agreement. A default of this Agreement ("Default") shall occur upon the failure of a Party in Breach of this Agreement to cure such Breach in accordance with Section 21.4.

21.2 Events of Breach. A Breach of this Agreement shall include:

(a) The failure to pay any amount when due;

(b) The failure to comply with any material term or condition of this Agreement, including but not limited to any material Breach of a representation, warranty or covenant made in this Agreement;

(c) A Party's abandonment of its work or the facilities contemplated in this Agreement;

(d) If a Party: (1) becomes insolvent; (2) files a voluntary petition in bankruptcy under any provision of any federal or state bankruptcy law or shall consent to the filing of any bankruptcy or reorganization petition against it under any similar law; (3) makes a general assignment for the benefit of its creditors; or (4) consents to the appointment of a receiver, trustee or liquidator;

(e) Failure of either Party to provide information or data to the other Party as required under this Agreement, provided the Party entitled to the information or data under this Agreement requires such information or data to satisfy its obligations under this Agreement.

21.3 Continued Operation. Except as specifically provided in this Agreement, in the event of a Breach or Default by either Party, the Parties shall continue to operate and maintain, as applicable, facilities and appurtenances that are reasonably necessary for the Transmission Owner to operate and maintain the Transmission System, or the Local Distribution Company to operate and maintain the Distribution System, in a safe and reliable manner.

21.4 Cure and Default. Upon the occurrence of an event of Breach, the non-Breaching Party, when it becomes aware of the Breach, shall give written notice of the Breach to the Breaching Party and to any other Person a Party to this Agreement identifies in writing to the other Party in advance. Such notice shall set forth, in reasonable detail, the nature of the Breach, and where known and applicable, the steps necessary to cure such Breach. Upon receiving written notice of the Breach hereunder, the Breaching Party shall have thirty (30) days, to cure such Breach. If the breach is such that it cannot be cured within thirty (30) days, the Breaching Party will commence in good faith all steps as are reasonable and appropriate to cure the Breach within such thirty (30) day time period and thereafter diligently pursue such action to completion. In the event the Breaching Party fails to cure the Breach, or to commence reasonable and appropriate steps to cure the Breach, within thirty (30) days of becoming aware of the Breach, the Breaching Party will be in Default of the Agreement. In the event of a Default, the non-Defaulting Party has the right to take whatever action at law or equity as may be permitted under this Agreement.

21.5 Right to Compel Performance. Notwithstanding the foregoing, upon the occurrence of an event of Default, the non-Defaulting Party shall be entitled to Commence an action to require the Defaulting Party to remedy such Default and specifically perform its duties and obligations hereunder in accordance with the terms and conditions hereof, and exercise such other rights and remedies as it may have in equity or at law.

ARTICLE 22. Term

22.1 Term. This Agreement shall become effective as of the Effective Date and shall continue in full force and effect so long as any Interconnection Point is connected to the Transmission System, except that it may be terminated by mutual agreement of the Parties.

22.2 Material Adverse Change.

(a) In the event of a material change in law or regulation that adversely affects, or may reasonably be expected to adversely affect, either Party's performance under this Agreement, including but not limited to the following:

(i) this Agreement is not accepted for filing by the FERC without material modification or condition;

(ii) NERC or ECAR prevents, in whole or in part, either Party from performing any provision of this Agreement in accordance with its terms; or

(iii) The FERC, the United States Congress, any state, or any federal or state regulatory agency or commission implements any change in any law, regulation, rule or practice which materially affects or is reasonably expected to materially affect either Party's ability to perform under this Agreement.

The Parties will negotiate in good faith any amendment or amendments to the Agreement necessary to adapt the terms of this Agreement to such change in law or regulation, and the Transmission Owner shall file such amendment or amendments with FERC.

(b) If the Parties are unable to reach agreement on any such amendments, then the Parties shall continue to perform under this Agreement to the maximum extent possible, taking all reasonable steps to mitigate any adverse effect on each other resulting from the Event. If the Parties are unable to reach agreement on any such amendments, Transmission Owner shall have the right to make a unilateral filing with FERC to modify this Agreement pursuant to Section 205 of the Federal Power Act and Local Distribution Company shall have the right to make a unilateral filing with FERC to modify this Agreement pursuant to Section 206 of the Federal Power Act. Each Party shall have the right to protest any such filing by the other Party and to participate fully in any proceeding before FERC.

22.3 Survival. The applicable provisions of this Agreement shall continue in effect after expiration, cancellation or termination hereof to the extent necessary to provide for final billings, billing adjustments and the determination and enforcement of liability and indemnification obligations arising from acts or events that occurred while this Agreement was in effect.

ARTICLE 23. Assignment/Change in Corporate Identity

23.1 Transmission Owner Assignment Rights. Transmission Owner may not assign this Agreement or any of its rights, interests, or obligations hereunder without the prior written consent of Local Distribution Company, which consent shall not be unreasonably withheld; provided however, that Transmission Owner may assign this Agreement or any of its rights or obligations hereunder without the prior consent of Local Distribution Company and may assign this Agreement to any entity(ies) in connection with a merger, consolidation, or reorganization, provided that the surviving entity(ies) or assignee owns the Transmission System, agrees in writing to be bound by all the obligations and duties of Transmission Owner provided for in this Agreement and the assignee's creditworthiness is equal to or higher than that of Transmission Owner.

23.2 Local Distribution Company Assignment Rights. Local Distribution Company may not assign this Agreement or any of its rights, interests or obligations hereunder without the prior written consent of Transmission Owner, which consent shall not be unreasonably withheld; provided however, that Local Distribution Company may, without the consent of Transmission Owner, and by providing prior reasonable notice under the circumstances to Transmission Owner, assign, this Agreement to any entity(ies) in connection with a merger, consolidation, or reorganization, provided that the surviving entity(ies) or assignee owns the Local Distribution Company, agrees in writing to be bound by all the obligations and duties of Local Distribution Company provided for in this Agreement and the assignee's creditworthiness is equal to or higher than that of Local Distribution Company.

23.3 Assigning Party to Remain Responsible. Any assignments authorized as provided for in this article will not operate to relieve the Party assigning this Agreement or any of its rights, interests, or obligations hereunder of the responsibility of full compliance with the requirements of this Agreement unless

(a) the other Party consents, such consent not to be unreasonably withheld, and
(b) the assignee agrees in writing to be bound by all of the obligations and duties of the assigning Party provided for in this Agreement.

23.4 This Agreement and all of the provisions hereof are binding upon, and inure to the benefit of, the Parties and their respective successors and permitted assigns.

ARTICLE 24. Subcontractors

24.1 Nothing in this Agreement shall prevent the Parties from utilizing the services of subcontractors as they deem appropriate; provided, however, the Parties agree that, where applicable, all said subcontractors shall comply with the terms and conditions of this Agreement.

24.2 Except as provided herein, the creation of any subcontract relationship shall not relieve the hiring Party of any of its obligations under this Agreement. Each Party shall be fully responsible to the other Party for the acts and/or omissions of any subcontractor it hires as if no subcontract had been made. Any obligation imposed by this Agreement upon the Parties, where applicable, shall be equally binding upon and shall be construed as having application to any subcontractor.

24.3 No subcontractor is intended to be or shall be deemed a third-party beneficiary of this Agreement.

24.4 The obligations under this Article shall not be limited in any way by any limitation on subcontractor's insurance.

24.5 Each Party shall require its subcontractors to comply with all federal and state laws regarding insurance requirements and shall maintain standard and ordinary insurance coverages.

ARTICLE 25. Dispute Resolution

Any dispute between the parties arising out of or relating to this Contract or the breach thereof shall be brought to the Administrative Committee. If the Administrative Committee can resolve the dispute, such resolution shall be reported in writing to and shall be binding upon the Parties. If the Administrative Committee cannot resolve the dispute within a reasonable time, the senior officer of Local Distribution Company or the senior officer of Transmission Owner may, by written notice to the senior officer of the other Party and the members of the Administrative Committee, withdraw the matter from consideration by the Administrative Committee and submit the same for resolution to the senior officers of the Parties. If the senior officers of the Parties agree to a resolution of the matter, such resolution shall be reported in writing to, and shall be binding upon, the Parties; but if said senior officers fail to resolve the matter within five (5) Business Days after its submission to them, then the Parties agree to try in good faith to settle the dispute by mediation administered by the American Arbitration Association under its Commercial Mediation Rules before resorting to litigation.

ARTICLE 26. Miscellaneous Provisions

26.1 This Agreement shall constitute the entire Agreement between the Parties hereto relating to the subject matter hereof. In all other respects, special contracts or superseding rate schedules shall govern Transmission Owner’s transmission service to Local Distribution Company.

26.2 No failure or delay on the part of Transmission Owner or Local Distribution Company in exercising any of its rights under this Agreement, no partial exercise by either Party of any of its rights under this Agreement, and no course of dealing between the Parties shall constitute a waiver of the rights of either Party under this Agreement. Any waiver shall be effective only by a written instrument signed by the Party granting such waiver, and such shall not operate as a waiver of, or estoppel with respect to, any subsequent failure to comply therewith.

26.3 Nothing in this Agreement, express or implied, is intended to confer on any other Person except the Parties hereto any rights, interests, obligations, or remedies hereunder.

26.4 In the event that any clause or provision of this Agreement or any part hereof shall be held to be invalid, void, or unenforceable by any court or Governmental Authority of competent jurisdiction, said holding or action shall be strictly construed and shall not affect the validity or effect of any other provision hereof, and the Parties shall endeavor in good faith to replace such invalid or unenforceable provisions with a valid and enforceable provision which achieves the purposes intended by the Parties to the greatest extent permitted by law.

26.5 The article and section headings herein are inserted for convenience only and are not to be construed as part of the terms hereof or used in the interpretation of this Agreement.

26.6 In the event an ambiguity or question of intent or interpretation arises, this Agreement shall be construed as if drafted jointly by the Parties and no presumption or burden of proof shall arise favoring or disfavoring any Party by virtue of authorship of any of the provisions of this Agreement. Any reference to any federal, state, local, or foreign statute or law shall be deemed also to refer to all rules and regulations promulgated thereunder, unless the context requires otherwise. The word “including” in this Agreement shall mean including without limitation.

26.7 This Agreement may be executed in one or more counterparts, each of which shall be deemed an original.

26.8 Each Party shall act as an independent contractor with respect to the provision of services hereunder.

IN WITNESS WHEREOF, Transmission Owner and Local Distribution Company have caused this instrument to be executed by their duly authorized representatives as of the day and year first above written.

Review and Approval	Initial	
JR McCormick	JRM	12/17/2024 | 1:34 PM EST
ML Hayward	MLH	12/17/2024 | 1:36 PM EST
SJ Herrygers	SJH	12/17/2024 | 1:44 PM EST
Approval as to Form		
Legal	KAM	12/17/2024 | 1:32 PM EST

CONSUMERS ENERGY COMPANY

Name: Tonya Berry

Title: Senior Vice President Transformation and Engineering

12/17/2024 | 1:55 PM

Tonya Berry
BEAA3C1321D54C4...

MICHIGAN ELECTRIC TRANSMISSION COMPANY, LLC, a Michigan limited liability company

By: ITC Holdings Corp., a Michigan corporation, its sole manager

DocuSigned by:
By: _____ 12/29/2024 | 9:08:25 PM EST
357A7F23DA8542F...

Name: Brian Slocum

Title: Senior Vice President and Chief Operating Officer

EXHIBIT 1 – Interconnection Points (Substations)

Addendum 14 - October 18, 2024

Substation

1. Abbe
2. Acme (04/10)
3. Alcona
4. Alder Creek
5. Alger
6. Algoma
7. **Alliance (05/24)**
8. Alma
9. Almeda
10. Alpena
11. Alpine
12. Amber
13. American Bumper
14. Arenac (05/23)
15. Arthur (06/06)
16. Ash Road (06/18)
17. Aubil Lake
18. Backus
19. Bagley
20. Bangor
21. Baraga (12/07)
22. Bard Road
23. Barnum Creek
24. Barry
25. Bass Creek
26. Batavia
27. Bay Road
28. Bayberry
29. Beals Road
30. Becker
31. Beaver Creek
32. Beebe
33. Beecher
34. Begole
35. Bell Road
36. Bennington
37. Benston (11/18)
38. Beveridge
39. Bilmar
40. Bingham
41. Birchwood (06/12)
42. Black River
43. Blackman
44. Blackstsone
45. Blinton
46. Blue Water
47. Bluegrass
48. Boardman
49. Boxboard
50. Bricker
51. Brickyard
52. Briggs & Stratton
53. Broadmoor
54. Bronco
55. Broughwell
56. Buck Creek
57. Bullock
58. Busch Road (02/08)
59. Caledonia
60. Calhoun
61. Camelot Lake
62. Campbell 138
63. Canal
64. Cannon
65. Carpenter Rd (08/06)
66. Carter
67. Cedar Springs
68. **Celery (03/24)**
69. Cement City
70. **Charge (05/24)**
71. Chase
72. Cheesman
73. Chicago
74. Churchill
75. Clare
76. Claremont
77. Clearwater
78. Cleveland
79. Club
80. Cobb
81. Cochran
82. Cole Creek
83. Colony Farm
84. Convis

85. Cork Street
86. Cornell
87. Cottage Grove
88. Covert
89. Cowan Lake
90. Crahen (10/07)
91. Croton
92. David
93. Dean Road
94. Deja
95. Delaney
96. Delhi
97. Denso Jackson
98. Derby
99. Discovery Way (04/11)
100. Dorr Corners
101. Dort
102. Dow Corning
103. Dowling
104. Drake Road
105. Duffield Rd
106. Dupont
107. Duquite
108. Dutton
109. East Paris
110. East Tawas
111. Easton
112. Edenville
113. Edwards (07/21)
114. Ellis
115. Elm Street
116. Elmwood
117. Emmet
118. Englishville
119. Eureka
120. Farr Road
121. Felch Road
122. Filer City
123. Fillmore
124. Flakeboard
125. Forest (12/16)
126. Forest Grove (12/18)
127. Fort Custer
128. Forty Fourth Street
129. Four Mile
130. Gaylord
131. Geddes (04/08)
132. Gleaner
133. Grand Blanc BOC
134. Gratiot
135. Greenwood
136. Grey Iron
137. Grodi Road
138. Gout
139. Hackett
140. Hagadorn
141. Hager Park
142. Halsey
143. Haring
144. Harvard Lake (06/09)
145. Hawthorne (11/22)
146. Hazelwood
147. Hemphill
148. Hendershot
149. Higgins
150. Hile Road
151. Hillman Cogen
152. Hodenpyl
153. Holland Road
154. Hotchkiss
155. Howell Road (12/21)
156. HSC
157. Hubbard Lake (12/07)
158. Huckleberry (05/22)
159. Hubbardston Road (06/10)
160. Hudsonville
161. Hughes Road
162. Hull Street
163. Iosco
164. Island Road
165. Jamestown
166. Karn 138
167. Kentwood
168. Keystone
169. Kinderhook (05/07)
170. Kipp Road
171. Kraft Avenue
172. Kromdyke (04/19)
173. Labarge
174. Lafayette
175. Latimer
176. Laundra (05/07)
177. Lawndale
178. Layton
179. Letts Road
180. Lewiston
181. Lindbergh
182. Livingston Peaker
183. Looking Glass
184. Lorin

185. Lovejoy
186. Ludington
187. Maines Road (03/17)
188. Manlius
189. Marquette
190. McGulpin
191. McNally
192. MCV
193. Meadowbrooke
194. Mecosta
195. Medusa
196. Michigan
197. Michigan Power (MPLP)
198. Miles Road
199. Milham
200. Mio
201. Monitor
202. Moore Road
203. Mullins
204. Murner (10/19)
205. Muskegon Heights
206. Neff Road
207. Nineteen Mile Road
208. North Belding
209. North Corunna
210. Northern Fibre
211. North Star (02/19)
212. Nugent Sand
213. Oakland
214. Oceana
215. Ogemaw
216. Orr Road (03/09)
217. Owosso
218. Packard
219. Page Avenue
220. Palisades
221. Parkville (08/12)
222. Parr Road
223. Parshallville
224. Pasadena
225. Pavilion
226. Pearline (06/11)
227. Pettis Road
228. Pigeon River/Rondo
229. Pingree (10/08)
230. Piston Ring P
231. Plaster Creek
232. Plum (07/10)
233. Plymouth Street
234. Plywood
235. Polkton (11/22)
236. Port Calcite
237. Port Sheldon
238. Porter
239. Portsmouth
240. Price Road (09/07)
241. Progress Street
242. Race Street
243. Raisin
244. Ransom
245. Ratigan (12/12)
246. Regal (01/13)
247. Renaissance
248. Rice Creek
249. Rifle River
250. Riggsville
251. **Riverbend (12/24)**
252. Rivertown
253. Riverview
254. Roedel Road
255. Rogue River (06/07)
256. Ryno (09/14)
257. Saginaw River
258. Samaria
259. Sanderson
260. **Santiago (12/24)**
261. Savidge
262. Scenic Lake (12/15)
263. Scott Lake
264. Seamless East/Seamless
265. Seven Mile (11/2020)
266. Simmons
267. Simpson (08/12)
268. Smith Creek
269. Snyder (06/17)
270. Sonoma (05/06)
271. Spaulding
272. Spruce Road
273. Stacey
274. Steelcase
275. Stillson
276. Stonegate
277. Stover
278. Stronach
279. Summerton
280. Tallman
281. Technical Drive (01/20)
282. Thetford
283. Thompson Road
284. Tihart

285. Tinsman
286. Tippy
287. Titus Lake
288. Trillium (06/07)
289. Trowbridge
290. Tuscola Bay
291. Twelfth Street
292. Twilight
293. Upjohn
294. Van Atta
295. Van Buren (06/08)
296. Vanderbilt
297. Vernon
298. Verona
299. Vevay
300. Viking Lincoln
301. Vrooman
302. Wakerly
303. Warner
304. Warren
305. Washtenaw
306. Wayland
307. Weadock
308. Wealthy Street
309. West Fenton (05/07)
310. Wexford
311. White Lake
312. White Road
313. Whiting
314. Whittemore
315. Willard
316. Withey Lake (05/06)
317. Zeeland

New Interconnections added for this year's DTIA are shown in **bold type**.

Interconnections added after May of 2002 will have the (month/year) in-service date after the substation name.

Note, this list of substations is not necessarily a list of the true points of facility ownership change between the Transmission Owner and the Local Distribution Company. This also is not a complete listing of all Local Distribution Company substations that have a 138 kV high-side supply voltage.

The generator sites or generator POIs referenced under this Exhibit are referenced herein because Local Distribution Company provides distribution service to the corresponding generators.

EXHIBIT 2 - Contact Information For Local Distribution Company's Representatives and Transmission Owner's Representatives

Local Distribution Company:

Consumers Energy Company
1945 West Parnall Road
Jackson, MI 49201

Attn: Executive Director, Electric Planning

Transmission Owner:

Michigan Electric Transmission Company, LLC
27175 Energy Way
Novi, MI 48377

Attn: Legal Department – General Counsel

Email: jdanna@itctransco.com

EXHIBIT 3

Intentionally Omitted

EXHIBIT 4 – Metering Specifications

Performance criteria:

1. Meters shall meet or exceed the latest version of ANSI C12.16 (Standard for Solid State Electricity Meters) specifications for solid state metering.

2. Current transformers used for metering shall meet or exceed an accuracy class of 0.3%. Secondary connected burdens shall not exceed rated burden of any current transformer. Current transformers shall comply with most current applicable ANSI Standards including C57.13 (IEEE Standard Requirements for Instrument Transformers) and C12.11 (Instrument Transformers for Revenue Metering 10 kV BIL through 350 kV BIL). Meter installations shall comply with manufacturer's accuracy and burden class information on the nameplate of each device.

3. Voltage transformers used for metering shall meet or exceed an accuracy class of 0.3%. Secondary connected burdens shall not exceed rated burden of any voltage transformer. Voltage transformers shall comply with most current applicable ANSI Standards including C57.13 (IEEE Standard Requirements for Instrument Transformers), and C12.11 (Instrument Transformers for Revenue Metering 10 kV BIL through 350 kV BIL). Meter installations shall comply with manufacturer's accuracy and burden class information on the nameplate of each device.

4. PT secondary circuits shall have a disconnect switch installed which provides a visible air gap for worker safety, and which allows for attachment of a protective safety tag.

EXHIBIT 5

Intentionally Omitted

EXHIBIT 6 - Jointly Owned Assets Ownership by Percent of Major Equipment
Addendum 14 – October 18, 2024

Substations

Jointly Owned Assets, Percentage Split by Major Equipment Count[1]

Substation Name	Distribution owned by Local Distribution Company	Transmission owned by Transmission Owner	Generation Owned by Local Distribution Company	Third-Party Assets	Last Revision Date
Alder Creek	99.99	0.01			4/15/19
Alma	66.67	33.33			10/24/03
Amber	66.67	33.33			4/15/19
Bangor	33.33	66.67			4/15/19
Bard Road	41.67	58.33			06/10/10
Bass Creek	83.33	16.67			4/15/19
Batavia	53.33	46.67			11/17/22
Bay Road	99.99	0.01			4/15/19
Beals Road	84.62	15.38			06/10/10
Beaver Creek	66.67	33.33			07/15/20
Beecher	77.42	22.58			11/17/22
Bell Road	99.99	0.01			4/15/19
Bennington	99.99	0.01			4/15/19
Beveridge	80.00	20.00			4/15/19
Bingham	57.14	42.86			11/7/23
Black River	66.67	33.33		0.00	4/15/19
Blackman	99.99	0.01			4/15/19
Blackstone	70.83	29.17			11/28/11

1 Notes:

(a) Transmission Owner shall own at least 0.01% of all jointly owned substations regardless of its status regarding ownership of major equipment.

(b) Changes, relative to the previous revision (addendum), are shown in bold type.

(c) At 120kV and above, third-party related assets will be included as part of the Transmission Owner's assets for purposes of making this calculation. Also, the third-party may share in the financial responsibility associated with O&M activities.

(d) Third-party may share in the financial responsibility associated with O&M activities.

(e) Below 120kV the third-party related assets will be included as part of the Local Distribution Company's assets for purposes of making this calculation. Also, the third-party may share in the financial responsibility associated with O&M activities.

Blinton	99.99	0.01			4/15/19
Broadmoor	95.83	4.17			4/15/19
Broughwell	99.99	0.01			4/15/19
Buck Creek	58.33	41.67			11/17/22
Bullock	76.00	24.00			11/20/08
Chase	62.50	37.50			4/15/19
Claremont	68.00	32.00			05/01/02
Cobb	57.69	42.31	0.00		07/15/20
Cork Street	33.33	66.67			4/15/19
Cornell	66.67	33.33			11/27/23
Cottage Grove	99.99	0.01			4/15/19
Croton	59.09	31.82	9.09		4/15/19
Dean Road	99.99	0.01			4/15/19
Delaney	80.00	20.00			4/15/19
Delhi	52.38	47.62			10/02/14
Dort	**99.99**	**0.01**			**10/18/24**
Dow Corning	80.00	20.00			4/15/19
Drake Road	99.99	0.01			4/15/19
Dupont	99.99	0.01			4/15/19
Duquite	99.99	0.01			4/15/19
East Paris	99.99	0.01			4/15/19
East Tawas	99.99	0.01			4/15/19
Emmet	61.54	38.46			4/15/19
Eureka	60.00	40.00			11/7/23
Felch Road	83.33	16.67			03/31/06
Four Mile	**88.00**	**12.00**			**10/18/24**
Gaylord	55.56	44.44	0.00		4/15/19
Grand Blanc BOC	25.00	75.00			4/15/19
Grey Iron	80.00	20.00			4/15/19
Halsey	76.92	23.08			10/24/03
Hazelwood	85.71	14.29			4/15/19
Hemphill	65.52	34.48			11/27/23
Higgins	68.75	31.25			11/7/23
Holland Road	75.00	25.00			4/15/19
Hotchkiss	99.99	0.01			4/15/19
HSC	33.33	66.67			11/28/11
Iosco	75.00	25.00			4/15/19
Island Road	76.92	23.08			4/15/19
Kentwood	99.99	0.01			4/15/19
Kipp Road	99.99	0.01			4/15/19
Kraft Avenue	99.99	0.01			4/15/19
Lafayette	99.99	0.01			4/15/19
Lawndale	70.59	29.41			11/28/12
Layton	99.99	0.01			4/15/19

Lindbergh	99.99	0.01			4/15/19
Manlius	99.99	0.01			4/15/19
Marquette	61.54	38.46			4/15/19
McGulpin	55.56	44.44			11/28/11
Mecosta	66.67	33.33			4/15/19
Milham	66.67	33.33			11/28/12
Monitor	86.67	13.33			4/15/19
Moore Road	50.00	36.36		13.64	11/17/22
North Belding	66.67	33.33			10/24/03
Oakland	62.50	37.50			4/15/19
Parr Road	85.71	14.29			4/15/19
Port Calcite	77.78	22.22			4/15/19
Ransom	72.73	27.27			11/23/21
Rice Creek	82.35	17.65			11/27/23
Riggsville	71.43	28.57			11/7/23
Riverview	63.16	36.84			11/23/21
Saginaw River	42.86	57.14			4/15/19
Samaria	90.00	10.00			4/15/19
Scott Lake	77.78	22.22			11/17/22
Spaulding	53.33	46.67			10/02/14
Spruce Road	99.99	0.01			4/15/19
Stover	37.50	62.50			11/23/21
Summerton	91.67	8.33			4/15/19
Tihart	66.67	33.33			11/28/12
Tippy	0.00	66.67	33.33		4/15/19
Upjohn	75.00	25.00			4/15/19
Vanderbilt	99.99	0.01			4/15/19
Verona	56.52	43.48			07/15/20
Vevay	99.99	0.01			4/15/19
Vrooman	62.50	37.50			4/15/19
Wackerly	90.00	10.00			4/15/19
Warner	99.99	0.01			4/15/19
Warren	81.82	18.18			4/15/19
Weadock	59.09	40.91	0.00		4/15/19
Wealthy Street	85.71	14.29			4/15/19
Wexford	85.71	14.29			4/15/19
White Lake	82.35	17.65			11/17/22
White Road	99.99	0.01			4/15/19
Whiting	53.85	46.15	0.00		4/15/19
Whittemore	99.99	0.01			4/15/19

Document Content(s)

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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

PROOF OF SERVICE

Jennifer Heston hereby certifies that, on the 6th day of November 2025, she served the Official Exhibits of Solar Technology LLC and this Proof of Service upon the persons identified on the attached service list by electronic mail.

/s/ Jennifer Heston
Jennifer Heston

Jennifer U. Heston
Digitally signed by Jennifer U. Heston
Date: 2025.11.06 13:04:29 -05'00'

Administrative Law Judge
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