From: Green, Leonard
To: Campbell, Kimberley
Cc: McDowell, Steve; Watson, Sam
Subject: FW: EV studies
Date: Tuesday, November 19, 2019 8:57:34 AM
Attachments: EPRI TVT paper 8.19.pdf
EPRI.Interops.white.paper.final.8.19.pdf
MN-PUC.17-879.Order.FINAL.2.19.pdf
MN PUC 2019-07-17 Final Order Pilots2.pdf
MI.PSC.Consumers.Orrder.1.19.U-20134 01-09-2019 No 1 - FINAL.pdf

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Kim C,

Please file this email from Phillip B. Jones and the attached documents in the Duke Electric Transportation Pilot dockets, E-2, Sub 1197 and E-7, Sub 1195.

Thank you. - Len

From: Phil Jones [mailto:phil@philjonesconsulting.com]
Sent: Monday, November 18, 2019 10:45 AM
To: McDowell, Steve <smcdowell@ncuc.net>
Subject: EV studies

Steve,
It was good to see you and Commissioner Clodfelter last week at your office in Raleigh. I was very pleased to join you for the swearing-in ceremony of the two new Commissioners last week, namely Jeff Hughes and Kim Duffley.

I have attached a few studies for your reference as you approach your "hearing" on Thursday, and review of what other States are doing (best practices in our view) on EV infrastructure, and specifically the utility role in EVSE and EV infrastructure. As follows:

- EPRI study on cost—benefit analysis: this is a new CBA that tries to go beyond the traditional tests, namely the RIM, TRC, UCT, SCT and others. EPRI does not purport to have all the answers to some of the more difficult questions and issues to resolve, like how to quantify environmental externalities (public health, GHG and carbon dioxide, as well as public health benefits from reduced tailpipe pollutants), and the significant savings (estimated to be $1200 to $1800 per year for average VMT and mpg for ICE car of 24 mpg or so). It doesn't have all the answers, but instead suggests a matrix to follow and the right questions to ask;
- EPRI interoperability paper, with ATE and EEI: published in August. Many stakeholders in the EV ecosystem believe that an open architecture is critical as the industry gets to scale both for light duty and heavy duty EVs. Today, we have a variety of proprietary network management systems (software) that don't necessarily talk well to each other. Utilities and Commissions should be aware of these issues;
- Minnesota PUC Order: we regard Minnesota as a best practice state that has both adopted good and comprehensive policy guidance (how utilities should file), as well as

two programs approved for Xcel Energy – EV fleets, and public infrastructure.

- Michigan PSC Order: again, we regard Michigan (along with Maryland and Oregon and others) as a best practice State that has approached the EV issues thoughtfully and comprehensively. This Order is from January, 2019 and is for the approval some pilot programs for Consumers Energy following a series of workshops and deliberations.

I hope these are useful. Please share with Commissioner Clodfelter as appropriate.

Best regards,
Philip

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ELECTRIC POWER
RESEARCH INSTITUTE

THE TOTAL VALUE TEST: A FRAMEWORK FOR EVALUATING THE COST-EFFECTIVENESS OF EFFICIENT ELECTRIFICATION

August 2019

10590772

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Abstract

This report presents the Total Value Test (TVT) as a metric for the cost-effectiveness of energy efficiency measures and programs, inclusive of electrification. The TVT represents an amalgam of the best attributes of the standard practice tests for energy efficiency that have been implemented by utilities and state regulatory bodies for decades, adapted and refined to include a more comprehensive set of benefits and costs characteristic of electrification considerations, including environmental impacts. The TVT can be applied to objectively compare the cost-effectiveness of electric, natural gas, or other options, and is not disposed to favor any particular technology based on how it is powered or fueled. The report provides a review and critique of the energy efficiency standard practice tests, presents the rationale and methodology of the TVT, and illustrates the use of the TVT in three case studies.

Keywords

Benefit-cost analysis
Carbon reduction
Demand-side management
Energy efficiency
Electrification
Standard practice manual
Total resource cost

Overview

Energy efficiency encompasses all forms of end-use energy, including electricity, natural gas, and other fuels. Efficient electrification represents an extension of energy efficiency that may be defined as follows:

> The application of electric powered end-use technology as a substitute for direct-use fossil-fueled or non-energized processes for customer homes, buildings, industries, or transportation that results in net economic benefit to the customer and net environmental benefits to society.

Efficient electrification can yield considerable benefits not only to customers who undertake this activity—in the form of lower overall energy costs and enhanced productivity, comfort, convenience, and so on—but also more broadly to electricity customers and society-at-large. One of the impediments to greater utility engagement in efficient electrification programs is determining their cost-effectiveness. Utilities and their regulators typically require a favorable estimation of cost-effectiveness to justify investment in programmatic activities with customers.

However, there is not yet an industry accepted cost-effectiveness framework with sufficient depth and breadth to appropriately quantify the value of electrification. The objective of this paper is to present a suitable cost-effectiveness framework for evaluating prospective efficient electrification programs.

To establish the cost-effectiveness framework proposed in this report, we first reviewed of existing frameworks for evaluating the cost-effectiveness of demand-side programs. This review includes the well-known cost-effectiveness "tests" originally established in the

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California Standard Practice Manual (SPM), subsequently published literature on the topic, and recent utility regulatory filings introducing new electrification programs. The literature review was supplemented with the findings of in-depth interviews with 15 experts on electrification and cost-effectiveness analysis.

Based on this review, we have concluded that the SPM tests are useful for assessing electrification cost-effectiveness at a conceptual level, although they are rarely applied for this purpose. Contrary to common perceptions, the tests account for considerations that are critical when evaluating efficient electrification programs. These considerations include, for instance, the cross-sector impacts of fuel switching, non-energy benefits, environmental impacts, grid management benefits, employment impacts, and productivity enhancements.

Among the various cost-effectiveness test perspectives defined in the SPM, the Societal Cost Test is the most aligned with our recommended framework for evaluating efficient electrification programs. Broadly, the Societal Cost Test determines whether costs to society at-large will be reduced with the introduction of a new program.

At the same time, the Societal Cost Test has developed a reputation among critics for being too "open ended" and allowing for a subjective interpretation of which benefits and costs to quantify and include in the assessment. The Societal Cost Test also uses a low "societal discount rate" which, by putting significant weight on longer term benefits, tends to be very generous to new demand-side programs.

To mitigate these concerns about the Societal Cost Test, we propose a revised test known as the **Total Value Test,** particularly for regulators who view their role as implementing social policy. The Total Value Test uses the utility's weighted average cost of capital as the discount rate (which is typically higher than a societal discount rate) but also includes the non-energy benefits and costs included in the Societal Cost Test as well as core customer cost savings.

Although the overarching California SPM framework is valid for evaluating efficient electrification, *implementation* of the SPM tests often falls short. The following are critical considerations when applying the Total Value Test:

1. **Identifying costs and benefits.** The Total Value Test takes the broadest possible perspective on the costs and benefits of efficient electrification programs. Although the aforementioned environmental impacts and non-energy benefits are important considerations, the Total Value Test weighs them against similarly important changes in energy resource costs and other benefits that may accrue directly to participants and/or non-participants. An advantage of the Total Value Test is that it comprehensively accounts for all of these possible sources of value rather than taking a narrow perspective that may exclude important considerations. Costs and benefits of efficient electrification programs included in the Total Value Test are summarized in Table 1.

2. **Including "non-energy" costs and benefits.** The inclusion of non-energy benefits and "market barrier costs" will take on increasing importance in an electrification context. New electric end uses will likely include a range of features with significant non-monetary benefits and costs to consumers. New research is needed to quantify these costs and benefits. Where they are not quantifiable, they should be given careful qualitative consideration—particularly when evaluating measures that are marginally failing the relevant cost-effectiveness tests. A useful approach adopted by states such as Vermont and Massachusetts is to apply qualitative "adders" to value non-energy benefits that cannot be quantified to a reasonable level of confidence yet are understood to have non-zero value.

3. **Accounting for policy goals.** Cost-effectiveness analysis that is conducted without consideration for policy goals will not yield conclusions that are useful for decision making. Therefore, the impacts of established policies should be accounted for in the baseline scenarios against which the electrification program is being compared. In other words, the baseline scenario should reflect the costs and market dynamics associated with the achievement of policy goals. The proposed electrification program can then be evaluated on the basis for which it increases or decreases costs and benefits under these conditions.

4. **Defining the Total Value Test "boundary."** Some existing cost-effectiveness tests, such as the Societal Cost Test, do not allow available subsidies to count as a net reduction in costs associated with an electrification program. The reason is that from a net societal perspective, subsidies to program participants are a cost to non-participants (for example, through tax payments). The two cancel one another out. However, utilities and state regulators may wish to define the boundaries of the Total Value Test at the state level. As a practical consideration, doing so would allow federal subsidies to be included as a benefit (that is, cost reduction) in the program.

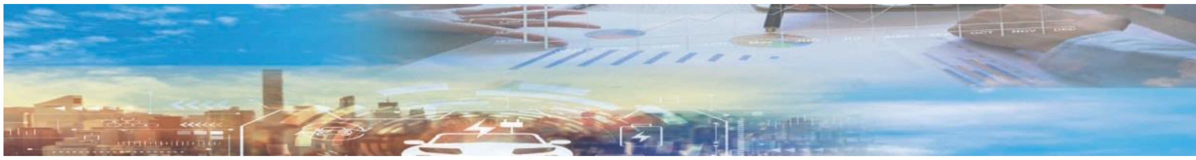


Table 1. Costs and Benefits of Efficient Electrification in the Total Value Test

Category	Example	Quantifiability
Program costs		
Administration costs	Marketing, measurement & verification	◒
Incentive payments	Rebates for equipment purchases	◒
Participant contribution to costs	Cost to consumer of equipment, net or rebate	◒
Third-party contribution to costs	Trade ally contribution to marketing costs	◒
System impacts		
Production capacity costs	New electricity generation peaking capacity	◒
Production energy costs	Reduced need for gasoline to power vehicles	◒
Cost of environmental regulations	Reduced gas utility compliance fees due to lower demand	◒
Fuel transmission capacity costs	Reduced need for natural gas pipeline expansion	◒
Fuel distribution capacity costs	Increased need for electric distribution capacity	◒
Line losses	Higher electricity line losses due to higher volume of sales	◒
Ancillary services	Provision of frequency regulation from new sources of flexible load	◒
Risk to the utility	Increased risk of stranded natural gas assets	◑
Renewable resource obligation	Higher RPS requirement due to higher electricity sales	◒
Energy market price effect	Increased wholesale electricity price due to peak demand growth	◑
Participant impacts		
Other resource costs	Increased water demand for hydroelectric power	◑
O&M costs	Elimination of need for regular oil changes for a gasoline vehicle	◑
Health impacts	Reduced medical costs	○
Productivity	Reduced product spoilage/defects	◑
Asset value	Improved property values	○
Economic well-being	Reduced foreclosures	○
Comfort	Vehicle noise reduction	○
Societal impacts		
Air quality	Reduced tailpipe emissions from gasoline vehicles	◑
Employment	Vendor/contractor staffing changes	◑
Economic development	Changes in gross domestic product	◑
Energy security	Reduced dependence on fuels from unstable regions	○
Public health	Reduced health insurance costs due to cleaner air	○

Key

- ◒ Well established methodology, easily obtainable data
- ◑ Less established methodology or difficult/costly to obtain data
- ○ Speculative, subject to high degree of uncertainty

"Quantifiability" represents the extent to which there is a well-established methodology for quantifying the impact, data is readily obtainable at a low cost, and there is limited uncertainty in the results

5. Near-term versus long-term costs and benefits. It is important to evaluate the cost-effectiveness of efficient electrification programs over a long-term study horizon. The benefits of electrification programs may extend well beyond the life of the equipment directly associated with the program (for example, charging infrastructure deployment that allows transportation electrification to overcome the chicken-and-egg problem of range anxiety). Electrification programs may also drive down technology costs over time. Alternatively, there is also the possibility of stranded costs associated with the fuel that was replaced by electricity. Ultimately, the time horizon over which the analysis is conducted and the use of a consistent discount rate are available tools for addressing these issues in the Total ValueTest framework.

Introduction

Replacing fossil-fueled end-use and non-energized processes with electric technologies, a conversion known as *electrification*, can yield considerable benefits not only to customers who undertake this activity but more broadly to electricity billpayers and society-at-large. This holds true for the buildings sector and especially for the transportation sector. Recent EPRI analysis found that electrification could feasibly lead to an increase in U.S. electric load of anywhere between 24% and 52% between now and 2050, while economy-wide emissions would decrease by 19% to 67% as a result.[1] Similarly, research by The Brattle Group found that achieving the technical potential for electrification of transport and buildings in the U.S. could more than triple the rate of total electricity sales growth by 2050, while nearly achieving an 80% reduction in energy-related CO_2 emissions if coupled with decarbonization of the power supply.[2]

One of the impediments to greater utility engagement in customer electrification programs is determining their cost-effectiveness relative to alternatives. Utilities and their regulators typically require a favorable estimation of cost-effectiveness to justify investment in programmatic activities with customers.

However, there is not yet an industry accepted cost-effectiveness framework with sufficient depth and breadth to appropriately quantify the value of electrification. The objective of this paper is to present a suitable cost-effectiveness framework and associated test for any type of energy efficiency measure or program *inclusive of efficient electrification*. The framework includes a comprehensive inventory of benefit and cost streams associated with electrification.

Efficient electrification may be defined as follows:

> The application of electric powered end-use technology as a substitute for direct-use fossil-fueled or non-energized processes for customer homes, buildings, industries, or transportation that results in net economic benefit to the customer and net environmental benefits to society.

Our approach begins with a review and assessment of existing frameworks for evaluating the cost-effectiveness of demand-side programs. This review includes the well-known frameworks established in the California Standard Practice Manual as well as subsequently published literature on the topic. Our review of the cost-effectiveness literature is intended to identify any gaps in the application of these tests to efficient electrification programs. *A Review of Current Practices* summarizes the literature review.

The literature review is followed by the findings of interviews with fifteen experts on electrification and cost-effectiveness frameworks. These findings are summarized in *Expert Perspectives*.

A Framework for Evaluating Electrification Cost-Effectiveness presents our recommended framework for evaluating the cost-effectiveness of efficient electrification programs. The cost-effectiveness framework is called the Total Value Test (TVT). Our specification of the TVT is derived from the literature review and interviews described in the preceding sections.

Case Studies illustrates the application of the TVT with three case studies. The case studies illustrate how the proposed TVT framework can be applied to electrification technologies in practice. The three case studies are (1) a municipal fleet of battery electric buses, (2) indoor agriculture, and (3) water heating.

The report concludes with a summary in *Conclusion*, with an appendix, *Assessing the Grid Flexibility Value of Electrification*, discussing treatment of the grid flexibility value of electrification.

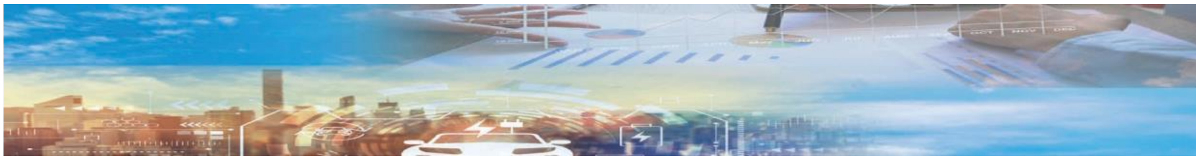
A Review of Current Practices

Introduction

Cost-effectiveness analysis has been utilized in utility investment decisions for decades. Methods specifically for evaluating demand-side initiatives were developed following the introduction of billpayer-

[1] EPRI, “U.S. National Electrification Assessment,” April 2018.

[2] Jurgen Weiss, Ryan Hledik, Michael Hagerty, and Will Gorman, “Electrification: Emerging Opportunities for Utility Growth,” The Brattle Group, January 2017.



funded conservation programs in the 1970s. The California Standard Practice Manual (SPM), published by the California Public Utilities Commission (CPUC) in 1983, has largely served as the authoritative manual for analyzing the cost-effectiveness of demand-side management (DSM) programs since its introduction.[3]

DSM cost-benefit analysis serves as a useful starting point when considering applicable approaches for evaluating the cost-effectiveness of billpayer-funded efficient electrification programs. Both DSM and efficient electrification involve changes in end-use energy consumption. These changes in consumption patterns and levels in turn drive the displacement or increase in use of resources such as power systems infrastructure, fossil fuels, and renewable energy.

This section summarizes the literature on demand-side cost-effectiveness, beginning with a review of the SPM. The SPM discussion is followed by a survey of subsequently published critiques of the SPM, with a focus on insights that are relevant to electrification initiatives. The section concludes with a brief review of recent utility efforts to evaluate the cost-effectiveness of new electrification programs.

The California Standard Practice Manual

History

The SPM was first developed by the CPUC in 1983. Subsequent revisions to the document were published in 1988 and 2001, through with no major conceptual changes to the framework described in the original version. The cost-effectiveness tests defined in the SPM have been adopted to varying degrees by most state regulatory commissions, often with nuanced modifications that are designed to address specific state objectives. The SPM is most commonly used to determine if utility investment in demand-side initiatives is in the public interest and, consequently, if the costs associated with these initiatives should be recovered from all consumers through retail rates.

The SPM has typically been used to evaluate utility-funded energy efficiency (EE) and demand response (DR) programs. However, the SPM tests were explicitly designed to also account for, using the terminology of its day, "fuel switching" and "load building" programs.[4] Electrification falls under these two categories.

[3] California Public Utilities Commission, "California Standard Practice Manual," October 2001.

[4] The terms are used in the SPM.

The SPM Framework

The SPM defines five cost-effectiveness tests that embody different perspectives on the cost and benefit categories to be considered when evaluating demand-side programs. The SPM provides commentary on the advantages, disadvantages, and appropriate uses of each of the five tests.

The SPM does <u>not</u> provide specific instructions for how to calculate each cost and benefit. For example, the SPM does not provide guidelines for establishing marginal energy costs or the load impact profile of a specific demand-side program. In California, these nuanced issues are addressed in much longer and more detailed "cost-effectiveness protocols" documents.[5] Other states have a range of established methodological precedents which can vary significantly.

The SPM touches on each of the following elements of a cost-effectiveness valuation framework:

- Cost-effectiveness perspective (participant, non-participant, administrator, utility system, or broader society)
- Relevant categories of benefits
- Relevant categories of costs
- Time horizon over which costs and benefits are appropriately calculated
- "Baseline" conditions for cost and benefits
- Impacts on baseline conditions attributable to the demand-side program
- Appropriate discount rate
- Appropriate treatment of tax-related incentives
- Appropriate cost-effectiveness metric(s) (i.e., net present value, benefit-cost ratio, levelized cost, etc.)

The Five Tests

The SPM includes five cost-benefit tests, as described below.

- **The Participant Test** provides an assessment of cost-effectiveness from the perspective of participating customers. Benefits are the sum of bill decreases and customer incentives paid by the utility. Costs are incurred by the participant to gain the benefits of the program and include any applicable participation fees.

[5] For instance, the demand response protocols can be found on the CPUC website: http://www.cpuc.ca.gov/General.aspx?id=7023.

- **The Ratepayer Impact Measure (RIM) test** provides an assessment of cost-effectiveness from the perspective of non-participants. Benefits are the reduction in avoided supply-side costs plus participant fees. Costs are the sum of revenue losses, incentives paid to customers, and utility administrative costs.
- **The Total Resource Cost (TRC) test p**rovides an assessment of cost-effectiveness from the perspective of customers and the utility. Benefits are the reduction in avoided supply-side costs. Costs are the program costs of the administering the program and incremental costs incurred by customers in joining the program.
- **The Utility Cost Test, also known as the Program Administrator Cost (PAC) test,** provides an assessment of cost-effectiveness from the perspective of the utility or the third-party program administrator. Benefits are the reduction in avoided supply-side costs. Costs are the sum of customer incentives and program administration costs.
- **The Societal Cost Test (SCT)** provides an assessment of cost-effectiveness from the perspective of society at-large. Benefits are the avoided societal costs, including all measurable externalities. The costs are usually the same as in the TRC test.

A summary of the five cost-effectiveness tests is provided in Table 2.

Table 2. Summary of the Five SPM Cost-Effectiveness Tests

Test	Key Question	Benefits	Costs
Participant Test	• Is the participant better off?	• Bill Decrease • Customer Incentives	• Program Costs (Participant) • Participation Fees
Total Resource Cost (TRC) Test	• Is resource efficiency improved?	• Avoided Supply-side Costs	• Program Costs (Total)
Ratepayer Impact Measure (RIM) Test	• Are rates lowered?	• Avoided Supply-side Costs • Participant Fees	• Revenue Loss • Customer Incentives • Program Costs (Utility)
Utility Cost Test (UCT) or Program Administrator Cost (PAC) Test	• Are revenue requirements lowered?	• Avoided Supply-side Costs • Participant Fees	• Customer Incentives • Program Costs (Utility)
Societal Cost Test (SCT)	• Are societal costs lower?	• Avoided Societal Costs, inclusive of Supply-side Costs and Social Externalities	• Program Costs (Total)

Critiques of the SPM

Overview

Since its introduction, the SPM has spawned a breadth of literature on cost-effectiveness evaluation methodology. To identify the most relevant publications, we conducted an internet search and drew upon Brattle's existing library of DSM cost-effectiveness resources. Expert interviews were used to further identify relevant resources (see *Expert Perspectives* for further details).

The purpose of our review was to identify gaps in the existing SPM methodologies, as well as alternative approaches. As such, we focused specifically on those publications that provide a critique of the SPM methodologies, or propose new frameworks for estimating cost-effectiveness. We gave less consideration to publications summarizing cost-effectiveness evaluations of specific utility DSM measures. Those studies focus mostly on implementation of the cost-effectiveness methodology and typically do not offer recommendations for improving the methodology.

The relevant studies are discussed below. They are presented in chronological order. We provide a brief summary of each study, followed by a discussion of the relevance of its conclusions in the context of electrification

SPM Critiques

Hobbs (1991): The "Most-Value" Test: Economic Evaluation of Electricity Demand-Side Management Considering Customer Value[6]

Hobbs (1991) highlights several shortcomings of the TRC test: (1) the test assumes customers do not react to program-induced retail rate change, (2) it assumes all market barriers preventing customers from installing the DSM measure on their own are reduced to zero, (3) it assumes customers use the same amount of energy service before and after the DSM program's introduction, and (4) it assumes customers receive the same quality of service after the program's

[6] Benjamin F. Hobbs, "The 'Most Value' Test: Economic Evaluation of Electricity
Demand-Side Management," *The Energy Journal* 12 No. 2 (1991): 67-91, http://www.jstor.org/stable/41322416.

introduction. To address these shortcomings, the study proposes the "Most Value Test" (also known as the Value Test or Net Economic Benefits Test), which quantifies the change in "consumer surplus."

Efficient Electrification Insights:

Electrification involves switching fuels and, as a result, changing the mix of fixed versus variable costs that faces a consumer. For example, a customer may pay an up-front premium for a heat pump to reduce variable heating costs. The lower marginal cost of heating could lead to an increase in consumption.[7] The Value Test presents a framework that allows for this potentially important dynamic to be captured. As discussed later in this section, it is challenging to quantify the costs and benefits that are included in the Most Value Test. However, subsequent studies have presented methodologies for performing the calculations.

Fulmer and Biewald (1994): Misconceptions, Mistakes and Misnomers in DSM Cost-Effectiveness Analysis[8]

Fulmer and Biewald (1994) summarizes and critiques each of the five SPM cost-effectiveness tests, plus the subsequent "Value Test." The study uses an "envelope" framework for determining which costs and benefits should and shouldn't be included in each test. It concludes that there are shortcomings of each SPM test.

Efficient Electrification Insights:

The authors find that implementation of all tests fails to fully account for "non-energy benefits." Non-energy benefits include those benefits that are not related to the avoided costs of the utility, such as improved comfort or health benefits from cleaner air. Non-energy benefits are particularly important in an electrification context, where new electric end-uses are likely to include additional non-energy benefits (e.g., quieter operation of electric vehicles) as well as potential inconveniences (e.g., customer anxiety about electric vehicle range).

Impacts on tax exposure for participants (e.g., exposure to increased property taxes due to increase in property value) are currently overlooked in most applications of the tests. Such tax impacts could be particularly significant when considering implications of retrofitting a building with alternative electric end-uses.

The authors also conclude that the RIM test does not provide enough detail to fully address issues related to cross-subsidies that may exist between participants and non-participants. For instance, the RIM test does not give a sense of the magnitude by which rates will go up (i.e., it does not account for differences in expenses versus rate base, and it does not account for whether rate increases will be contained within the customer class or spread across all customers). Given current equity concerns related to electrification (such as perceptions that certain electrification opportunities are only accessible by higher-income households), it would be prudent to develop a more rigorous method for understanding the distributional impacts of electrification programs.

To establish avoided costs, the authors suggest that detailed models of the power system be run with and without inclusion of the proposed demand-side initiative. While this is more of an implementation issue than a cost-effectiveness framework issue, it could be particularly important in the current environment of rapid renewables growth, where marginal costs are generally decreasing but the value of flexibility is rising (and is difficult to quantify in the absence of simulation modeling).

Finally, the authors indicate that standard application of the TRC test values avoided fuel cost at the cost of supply, whereas a literal interpretation of the definition of the test calls for the avoided fuel to be valued at the "retail" price (tariff or market price). Given that electrification programs hinge on fuel switching, the appropriate treatment of fuel cost is particularly important and should be evaluated carefully.

Herman and Hicks (1995): From Theory Into Practice: One Utility's Experience with Applying the Value Test[9]

Herman and Hicks (1995) addresses criticism that the Value Test is useful in theory but impractical to implement. In doing so, the study presents an example of how the Value Test was implemented for one New England utility.

Efficient Electrification Insights:

The study points out that the challenge with the Value Test – as well as other tests – is its difficulty to quantify non-energy benefits (e.g. improved comfort) and market barrier costs (e.g. technology risk

[7] This so-called "rebound effect" is discussed conceptually in the energy efficiency literature, but there is little evidence to substantiate this claim. Data on efficiency improvements in lighting suggests a minor rebound effect (https://www.nrdc.org/onearth/rebound-effect-real).

[8] Mark Fulmer and Bruce Biewald, "Misconceptions, Mistakes and Misnomers in DSM Cost-Effectiveness Analysis," *ACEEE Summer Study Proceedings* Volume 7 (1994): 73-83.

[9] Patricia Herman and Elizabeth G. Hicks, "From Theory into Practice: One Utility's Experience with Applying the Value Test," *ACEEE Summer Study Proceedings* Volume 8 (1994): 77-87.

aversion). The authors provide several practical approaches to quantifying these costs and benefits. Given the potentially high degree of importance of both non-energy benefits and market barrier costs in electrification efforts, it will be important to explore such approaches. *A Framework for Evaluating Electrification Cost-Effectiveness* provides a review of such techniques.

Earle and Faruqui (2006): Toward a New Paradigm for Valuing Demand Response[10]

Earle and Faruqui (2006) discusses the application of the SPM tests specifically to demand response (DR) programs. The study provides several recommendations for how the SPM tests can be improved to better account for the cost and benefits of DR, though the recommendations are largely more generally applicable to demand-side initiatives

Efficient Electrification Insights:

The authors' focus on DR is relevant in the sense that the electrification of various end-uses will introduce the potential for more load flexibility. It is important to recognize this flexibility value in cost-effectiveness evaluation of electrification programs. Further, the authors indicate that the DR of its day typically does not provide a reliability benefit beyond the avoided cost of capacity. This is often misunderstood by those who wish to assign both an avoided capacity cost and an additional reliability benefit to demand-side resources such as the flexible EV charging or electric heating.

The authors indicate that the TRC test penalizes measures that increase energy use, even though the customer may derive positive value from that incremental use. This is similar to the treatment of non-energy benefits discussed in prior studies and is an important consideration in load-building electrification initiatives.

It is recommended that uncertainty be incorporated into cost-effectiveness assessments through probabilistic analysis. Given the nascent state of some forward-looking electrification programs (relative to conventional EE and DR programs), this may have significant merit in an electrification context.

Demand-side initiatives can have an impact on market prices, particularly for high-priced hours with a steep demand curve and/or ancillary services products such as frequency regulation for which there is a limited need. This effect is sometimes referred to as the demand response induced price effect (DRIPE). While neither a cost nor a benefit in the TRC test, the marginal price impact is an important consideration from a policymaking standpoint. With respect to electrification, if this impact is considered it will be important to look outside of electricity markets and include market price effects for natural gas and other impacted fuels.

EPRI (2010): A Framework for Evaluating the Benefits and Costs of Investments in Electric Vehicle Infrastructure[11]

While not a direct critique of the SPM, the authors provide an alternative detailed framework specifically for evaluating the costs and benefits of electric vehicles.

Efficient Electrification Insights:

The proposed framework in its entirety represents a societal view of costs and benefits of electrification, but it highlights the many different industries and stakeholders that could be impacted positively or negatively by transportation electrification. This demonstrates that there may be additional perspectives beyond those presented in the five SPM tests that are worth policymaking consideration. For instance, a state energy regulator may want to consider the specific impact of electrification initiatives on natural gas utilities, including the possibility of stranded gas assets. Such considerations will be important in establishing policies and programs that transition to electrification in a cost-effective manner.

Neme and Kushler (2010): Is it Time to Ditch the TRC? Examining Concerns with Current Practice in Benefit-Cost Analysis[12]

Neme and Kushler (2010) highlight two main concerns with the TRC and its widespread adoption by state commissions. First, as discussed above, application of the TRC test commonly ignores non-energy benefits (NEBs). The authors cite several studies indicating that NEBs can be even larger than the energy benefits of demand-side programs. Second, the TRC test does not treat demand-side and supply-side resources equally. For instance, the authors point out that utility decisions to purchase generation do not penalize the generation based on any subsidies it is receiving, whereas tax incentives for demand-side initiatives are a consideration in some cost-effectiveness tests. Similarly, utility decisions to

[10] Robert Earle and Ahmad Faruqui, "Toward a New Paradigm for Valuing Demand Response," *The Electricity Journal* 19(4) (May 2006): 21-31.

[11] Electric Power Research Institute, "A Framework for Evaluating the Benefits and Costs of Investments in Electric Vehicle Infrastructure," December 2010.

[12] Chris Neme and Marty Kushler, "Is it Time to Ditch the TRC? Examining Concerns with Current Practice in Benefit-Cost Analysis," *ACEEE Summer Study on Energy Efficiency in Buildings* Volume 5 (2010): 299-310.

contract for output from behind-the-meter generation do not account for the customer's costs of installing the unit, while the TRC includes demand-side installation costs.

The authors feel that the best solution is to rely on the PAC test, as this does not require the calculation of difficult-to-quantify non-energy benefits and puts demand-side initiatives on a level playing field with supply-side resources.

Efficient Electrification Insights:

The authors raise the point that energy efficiency is often packaged with other premium features (i.e., typically the low cost, basic appliance model will not be energy-efficient, and buying efficiency also requires buying other features). A modern electrification analog is EVs, which are not typically entry-level models – although the EV market is evolving with new vehicles at lower price points.

The authors make an interesting case for putting more emphasis on the PAC test in cost-effectiveness evaluations. This highlights the point made in the SPM that it is necessary to consider multiple perspectives when evaluating electrification programs. Utilities, regulators, and stakeholders too often rely on a literal interpretation of one test as the basis for their conclusions about a program's cost effectiveness.

Lazar and Colburn (2013): Recognizing the Full Value of Energy Efficiency[13]

Lazar and Colburn (2013) discusses a broad range of issues related to demand-side cost-effectiveness evaluation, including a critique of the SPM and the Value Test. The report presents a comprehensive list of costs and benefits for consideration in the evaluation of DSM programs, as well as several instructive examples of misapplications of the SPM tests in practice.

Efficient Electrification Insights:

The authors present the Societal Cost Test (SCT) as the recommended standard for evaluating demand-side programs. While this tends to be a less-utilized test in many states, in part due to challenges quantifying the value of externalities, it is a particularly important test to consider for electrification programs, which are now commonly driven by decarbonization efforts. Further, electrification initiatives may have significant costs and benefits that extend beyond the utility service territory, which is the focus of the TRC.

National Efficiency Screening Project (2017): National Standard Practice Manual for Assessing Cost-Effectiveness of Energy Efficiency Resources[14]

National Efficiency Screening Project (2017) proposes a "principles based" cost-effectiveness Resource Value Framework rather than the more prescriptive tests presented in the SPM. The authors cite the regulator's core mission of determining what is in the "public interest" as the overarching driver of determining how to approve demand-side initiatives. In doing so, the authors emphasize that consistency with public policy goals should be a key consideration when determining approval of demand-side programs.

Efficient Electrification Insights:

The authors' focus on the importance of consistency with public policy objectives is relevant, as electrification initiatives are often presented, at least in part, as efforts to promote the policy objective of decarbonization. As such, the authors suggest that there is a significant subjective aspect of demand-side cost-effectiveness evaluation. Some regulatory subjectivity is required when it comes to weighing the non-quantified benefits of marginally failing measures. It is important to consider a variety of test perspectives rather than relying on a single benefit-cost ratio. Conversely, it is important to maintain a consistent economic basis for establishing cost-effectiveness, and to allow economics rather than politics to dictate technology choice.

Current Utility Practices

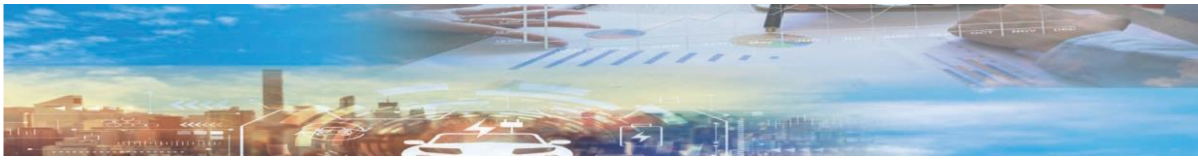
Overview

As a complement to the theoretical focus of the literature on cost-effectiveness, we reviewed actual utility reports or regulatory filings that included quantitative information about costs and/or benefits of electrification programs. We identified and reviewed eight such studies.

In several cases, the electrification proposals were not subject to comprehensive cost-effectiveness analysis, because they were only being proposed as pilot programs. Otherwise, the analyses generally followed established cost-effectiveness protocols in their respective states, relying on RIM, TRC, and SCT frameworks. Thus far, the

[13] Jim Lazar and Ken Colburn, "Recognizing the Full Value of Energy Efficiency (What's Under the Feel-Good Frosting of the World's Most Valuable Layer Cake of Benefits)," Regulatory Assistance Project, September 2013.

[14] Tim Woolf et al., "National Standard Practice Manual for Assessing Cost-Effectiveness of Energy Efficiency Resources, Edition 1," National Efficiency Screening Project, May 18, 2017.



SCT seems to have been used more commonly for electrification than in standard DSM contexts, presumably due to the societal impact of electrification programs (including decarbonization). A summary of the utility studies is provided in Table 3 and source documents are listed in the *References* section of this report.

Table 3. Utility Assessments of Costs and Benefits of Electrification Programs

Utility	State	Description	Tests Used
AEP	Ohio	EV charging load control program	"Regional Test" [1], RIM
Ameren	Missouri	EV charging infrastructure and C&I electrification	Modified TRC
Avista	Washington	Deployment of EV supply equipment (mostly chargers)	None [2]
City of Palo Alto	California	Residential heat pump program	SCT, RIM
Kansas City Power & Light	Kansas	Deployment of non-residential EV supply equipment	None [2]
National Grid	Rhode Island	Portfolio of transportation and heating electrification programs	SCT, RIM
Pepco	Maryland	EV charging demand management	None [2]
Portland General Electric	Oregon	Portfolio of transportation electrification programs	RIM, TRC, SCT
Southern California Edison	California	Deployment of EV supply equipment	None [2]

Notes:
[1] The regional test perspective appears to be a hybrid of the TRC and SCT.
[2] The pilot program was not subjected to cost-effectiveness screening, but filings include a detailed list of cost, typically split between utility costs and billpayer costs.

Conclusions

The literature review has led us to "Top 10 List" of considerations for assessing the cost effectiveness of energy efficiency inclusive of efficient electrification:

1. **Broadly, the SPM appears relevant and applicable.** The SPM is not broken. In fact, it directly includes considerations appropriate for electrification-type programs. However, several refinements and additions to the SPM methodologies can improve its application to electrification projects. We explore this theme in later sections of this report.

2. **Carbon reduction is a key environmental policy driver in some jurisdictions.** Energy efficiency and electrification programs in some states are driven by the policy objective of decarbonization, which can have impacts that extend significantly beyond the electric utility system.

3. **Non-energy benefits and costs merit further research, such that they can be quantified where possible or qualified as warranted.** The inclusion of non-energy benefits and "market barrier costs" will also take on increasing importance in an electrification context. New electric end-uses, particularly in transportation, will likely include a range of features with significant non-monetary benefits and costs to consumers. New research is needed to quantify these costs and benefits. Non-quantifiable benefits and costs should still be carefully considered, particularly when evaluating measures that are marginally failing the relevant cost-effectiveness tests. A useful approach adopted by states such as Vermont and Massachusetts is to apply qualitative "adders" to value non-energy benefits that cannot be quantified to a reasonable level of confidence yet are understood to have non-zero value.

4. **It is important to evaluate program impacts from multiple perspectives—societal, customer, and utility.** It is critical to consider a range of perspectives when evaluating the cost-effectiveness of electrification programs. While this is generally true of cost-effectiveness evaluations, it is particularly important in an electrification context where multiple stakeholder groups can be significantly impacted.

5. **Pilots should not need to demonstrate cost-effectiveness.** Consistent with observed practices around the U.S., any type of pilot, electrification or otherwise, should not be required to demonstrate cost-effectiveness. Rather, these pilots are implemented, at least in part, to determine whether large-scale electrification programs could be cost-effective.

6. **Additional detail on the distribution of bill impacts is needed.** While the RIM test can provide an initial assessment of the impact of electrification programs on the rates and bills of non-participants, further analysis is needed to better reflect these impacts, with a focus on program eligibility and impacts across income segments. The RIM does not account for other types of benefits from energy efficiency that may accrue to non-participating customers, such as non-energy benefits or demand reduction induced price effects (DRIPE) in RTO and ISO markets.

7. **Uncertainty analysis should be included in cost-effectiveness evaluations.** The nascent nature of electrification programs, compared to conventional DSM programs, calls for better accounting for uncertainty in projections of future impacts, costs and benefits. Uncertainty can be addressed through probabilistic analysis and advanced data analytics, rather than developing point-estimates of cost-effectiveness.

8. **Consideration should be given to the flexibility value of electrification.** Even if a proposed electrification program does not include a specific provision for demand management, assessment of benefits should recognize that the new electric load may have future flexibility value for the grid, as a function of its end-use characteristics and market mechanisms for monetizing flexibility. This consideration of grid flexibility benefits should apply to any form of demand-side program, including energy efficiency and demand response programs that target peak demand hours.

9. **Power simulation modeling will be increasingly important for valuing electrification programs.** Rather than simply relying on static estimates of marginal costs when estimating the impacts of electrification programs, it may be necessary to perform more detailed simulations of the power system. This will capture important issues related to the depth of the need for certain valuable resources and will better capture new issues being introduced in an increasingly decarbonized power supply mix.

10. **Programs should be cost-effective, not just satisfy policy objectives.** Just because an electrification program may be consistent with certain policy goals, that alone does not necessarily justify its development. There may be alternative, cheaper means for achieving the same goal. Thus, cost-effectiveness analysis should always be a key consideration when evaluating new electrification opportunities.

Expert Perspectives

Background

As a complement to our review of the literature on cost-effectiveness, we interviewed fifteen experts about the economics of efficient electricity. They were selected to provide us a sampling of views from energy efficiency organizations, state commissions, utility trade associations, and national research laboratories.

These phone interviews were designed to help us understand diverse perspectives on efficient electrification, with written questions submitted in advance.

Each conversation began with a proffered definition of efficient electrification, followed by asking for general comments on efficient electrification and the role of utilities in promoting it. Interviewees were then asked to answer one or more of the following seven questions:

1. Do you think it is a good idea for utilities to pursue efficient electrification?

2. Should utilities be allowed to recover expenditures for efficient electrification from all customers, just as they are recovered today for energy efficiency expenditures?

3. Should utilities be allowed to put expenditures for efficient electrification in the rate base? For example, could assets like electric vehicle charging stations and related infrastructure be rate-based in a similar manner as investments in transmission or distribution assets? If not, what are the key differences? Is there a way to reconcile these distinctions?

4. Should utilities be allowed to earn incentives for attaining efficient electrification goals, just as they are allowed (in some states) to earn incentives for attaining their energy efficiency goals?

5. Are there particular economic tests that should be applied to efficient electrification expenditures before determining their eligibility for cost recovery, and possible rate-basing, from customers?

6. Should California's Standard Practice Manual (SPM), which has been applied nationwide to assess energy efficiency programs, be expanded to include a sixth test for efficient electrification?

7. Do you have any materials that you can share with us as we proceed with our study?

Some experts provided an overall response to the questions, some answered a few of the questions, and some answered them all. As expected, there were both areas of agreement and disagreement among the experts.

Themes

In their initial comments, some of the experts expressed multiple definitions of efficient electrification. Some equated it with "fuel switching" between electricity and fossil fuels (e.g. natural gas) for space heating, water heating, and process heating. Others equated it with new uses of electricity, such as in transportation. A couple of interviewees suggested that "decarbonization" is a preferable term. Further, some felt that the definition of efficient electrification should also refer to its potential to enhance the flexibility of the power system.

In general, there was a broad base of support among the interviewees for pursuing efficient electrification that reduces emissions of carbon and other criteria pollutants and lowers customer costs of energy by reducing total energy consumption and/or increasing productivity. Some experts said that efficient electrification would be driven by state legislation, such as SB 350 in California, acknowledging that policy drivers would vary by state.[15]

Experts emphasized the importance of recognizing the distinction between efficient electrification versus traditional utility "load building" activities, as pursued in the 1950s and 1960s. The distinction is that efficient electrification must contribute to societal objectives, such as lowering carbon emissions, while also reducing customer costs or improving power system flexibility, with additional utility load as a byproduct.

In terms of evaluating the cost-effectiveness of utility-funded efficient electrification programs, it was stated that the SPM was originally developed for evaluating energy conservation and load management programs.

Some experts articulated that the TRC, the most widely used test in the country, has the following limitations:

1. Only considers non-energy benefits that can be monetized. Those are included in the Societal Cost Test but they are hard to measure;

2. Ignores the response of customers to the change in rates that might follow the implementation of demand-side programs, i.e., price elasticity;

3. Overlooks the value consumers gain from consuming electricity, i.e., consumer surplus;

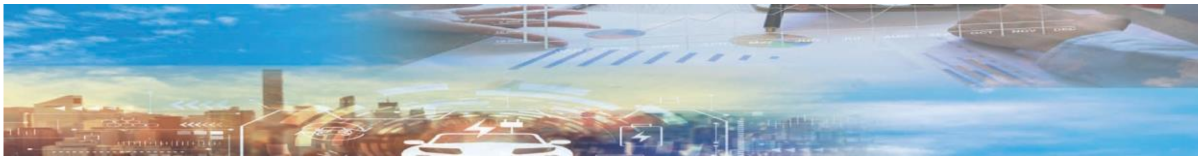
4. Assumes that avoided costs are constant regardless of the amount of demand-side programmatic activity – a limitation that can be overcome through production cost simulation models.

Other experts noted that new types of demand-side programs introduced since 2001 do not necessarily fit within the confines of the SPM methodology. For example, advanced demand response programs that emphasize load flexibility and efficient electrification may require the introduction of a new test that goes beyond the five in the SPM repertoire.

While some interviewees asserted that utilities have a natural role to promote and lead efficient electrification efforts, others argued that this is not self-evident. One expert noted that electrification of the Port of Oakland, California was implemented by the Port without any utility involvement simply because it made economic sense for the Port Authority and for shippers.

Some experts said that efficient electrification should not be presumed the exclusive purview of utilities, but rather as an opportunity for end-use customers and market-driven actors to pursue. This point is punctuated by the assertion that efficient electrification can be enabled solely by having appropriate market incentives. As a counterpoint, one expert noted that having the right codes and standards is more important than providing incentives to utilities or other market actors, since the former had been more impactful than the latter in attaining energy efficiency goals.

[15] California Senate Bill 350, "Clean Energy and Pollution Reduction Act" (SB 350).



Others noted that the objective of efficient electrification – market transformation to promote decarbonization – should be pursued though all channels including, but not exclusively, utilities.

On the issue of providing incentives to utilities to pursue efficient electrification, some experts stated that utilities will naturally benefit from increased electricity sales and improved load factors, yielding better earnings. The argument continues that as "natural beneficiaries" of electrification, utilities do not need special incentives for undertaking activities in their self-interest. Most such electrification programs would pass the Ratepayer Impact Measure (RIM) test, insofar as it would lower rates for all customers.

Experts pointed out the need for utility incentives for energy conservation, which lowers electricity sales, decreases recovery of fixed costs, and lowers earnings. By that reasoning, some posit that utilities may *not* need similar incentives to pursue efficient electrification, which has the effect of increasing electricity sales, increasing recovery of fixed costs, and raising earnings.

However, in states that have decoupled electric utility revenues from sales to align incentives and reduce barriers for energy efficiency programs, the natural utility incentive for efficient electrification is diminished. Hence, utilities in such states may require some earnings opportunities to undertake efficient electrification initiatives, whether in the form of rate basing infrastructure or incentive payments or performance incentives.

An additional point made was that market barriers for energy efficiency programs, which have existed over the past four decades, may not exist for efficient electrification programs. It was also suggested that in the future, cost-of-service regulation may give way to performance-based regulation and that change in regulatory paradigm would have to be considered when designing incentives for utilities to promote efficiency electrification.

A couple of experts suggested using the "Three-Prong Test" for evaluating efficient electrification programs, which has been applied for many years by the California Public Utilities Commission (CPUC) as a screening tool for energy efficiency programs in the state. In this test, a program must simultaneously pass the TRC test, lower carbon emissions, and lower total BTUs of energy consumed.

While the Three-Prong Test appealed to some interviewees for going beyond the traditional Total Resource Cost (TRC) test, it did not appeal to others who find it too stringent for evaluating efficient electrification programs. Experts generally acknowledged that very few efficient electrification programs would pass the Three-Prong Test, leading to a sub-optimal social outcome. These experts particularly questioned why reducing source energy consumption should be a requirement of decarbonization initiatives when, in fact, a net increase electricity consumption (replacing fossil-fueled end use) could have environmentally beneficial results in regions with a less carbon-intensive power supply mix.

Moreover, some experts opined that a demand-side management program should be deemed appropriate for pursuit if it advances any one of the following three policy goals without adversely impacting the other two:

- Lowers carbon emissions
- Lowers energy costs
- Improves grid flexibility

In evaluating the cost-effectiveness of efficient electrification, some parties suggested a modified TRC test, such as put forward by Ameren in its "Charge Ahead" electrification program filing in Missouri.[16] This test focuses on the benefits that would accrue from electrification in the form of reduced use of other fuels. One expert stated that fuel substitution is considered in the TRC test but only in the context of electricity and natural gas. The modified TRC includes other fossil fuels in the computations, such as gasoline, diesel and propane.

There was widespread agreement among the interviewees that carbon reduction benefits must be factored into any new cost-benefit calculus. Thus, some experts suggested using the "Resource Value Test" in the National Standard Practice Manual (NSPM), a cost-effectiveness framework that can apply to demand-side or supply-side options.[17] The Resource Value Test does not propose a specific formula for quantifying costs and benefits, but rather presents a set of principles for assessing cost-effectiveness. For instance, the Resource Value test asserts that analyzed costs and benefits should account for state policy objectives and that all assessments should be forward-looking. But there was disagreement among interviewees on how to quantify non-utility costs and benefits with this test, with some arguing that any answer could be derived depending on what

[16] Direct Testimony of David K. Pickles, on behalf of Union Electric Company, Missouri Public Service Commission, File No. ET-2018-0132, February 22, 2018.
[17] Tim Woolf, et al., "National Standard Practice Manual for Assessing Cost-Effectiveness of Energy Efficiency Resources, Edition 1," National Efficiency Screening Project, May 18, 2017.

values are assumed. Concern was also expressed that the general nature of this test may favor policy objectives over economics as the chief determinant of cost-effectiveness.

Implications for Electrification Cost-Effectiveness Analysis

The expert interviews identified important considerations for conducting cost-effectiveness analysis of efficient electrification programs. The following key takeaways emerged from the interviews as points of near consensus agreement.

1. Challenges and controversies of evaluating cost-effectiveness are driven more by decisions of how to implement the tests than by the conceptual design of the tests themselves. Implementation of the tests must ensure that costs and benefits are given equal treatment (e.g., include non-energy benefits if including non-utility costs, and vice versa).
2. The principles defined in the National Standard Practice Manual (NSPM) are important to consider, as the Resource Value Test is gaining visibility in several jurisdictions. The implication is to establish an evaluation framework that allows for consideration of state policy objectives. However, on a closer examination, the NSPM does not differ conceptually from the California SPM broadly defined.
3. Improved power system flexibility is an important and often overlooked benefit of electrification that should be included in cost-effectiveness analysis.
4. Non-energy benefits and costs are likely to play a significant role in the evaluation of electrification programs. This was also a conclusion of the literature survey in *A Review of Current Practices*.
5. Efficient electrification is an important element of decarbonization efforts. Environmental impacts – at a minimum those that can be monetized – should be included in the evaluation of electrification programs.

A Framework for Evaluating Electrification Cost-Effectiveness

Introduction

This study set out to determine if there are gaps in existing cost-effectiveness frameworks when applied to efficient electrification programs. The basis for this assessment included a review of the literature, a close examination of the California Standard Practice Manual (SPM), and interviews with industry experts, as discussed in *A Review of Current Practices* and *Expert Perspectives*.

Based on this review, we have concluded that the SPM tests, as originally conceived, are appropriate for assessing electrification cost-effectiveness. The SPM tests account for considerations that are critical when evaluating efficient electrification programs, such as the cross-sector impacts of fuel switching, non-energy benefits, grid management benefits, environmental impacts, employment impacts, and productivity enhancements.

However, while the overarching California SPM framework is valid for evaluating efficient electrification, *implementation* of the SPM tests often falls short. This is true even for the most common use of the SPM framework, which is its application to energy efficiency programs. Further deficiencies have been observed in alternative applications of the test, such as for demand response and electrification.

Considering that efficient electrification programs present unique characteristics not found in conventional DSM programs, correct implementation of the California SPM is imperative. Therefore, this section presents recommendations for effectively applying the California SPM tests in the context of efficient electrification, and more broadly to energy efficiency in general. While it is beyond the scope of this paper to comprehensively cover all implementation details, we provide critical guidelines and considerations.

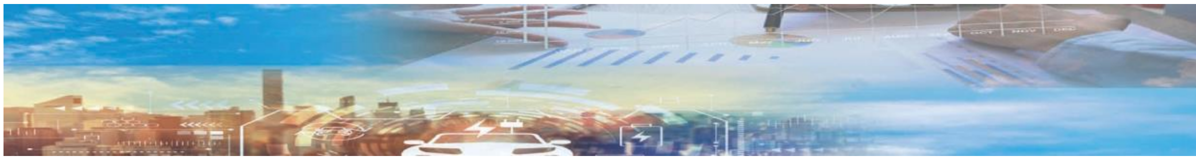
The California SPM and Efficient Electrification

Debunking myths about the SPM

Despite the SPM's long history of use to evaluate DSM programs, the SPM's nuances are often misunderstood by industry practitioners. Our interviews with industry experts – and close re-examination of our own understanding of the SPM – identified several commonly held misperceptions about the California SPM tests. We discuss myths directly relevant to the assessment of efficient electrification programs below.

Myth #1: The SPM does not account for fuel switching

The SPM explicitly accounts for fuel switching. Contrary to some perceptions, the SPM's focus extends beyond programs that reduce electricity consumption. Categories of programs that are specifi-



cally described in the SPM include "fuel substitution" and "load building."[18]

In discussing the nuances of "fuel substitution" programs, the SPM uses residential heat pumps – a common efficient electrification program – as an example:

> "Categorizing programs is important because in many cases the same specific device can be and should be evaluated in more than one category. For example, the promotion of an electric heat pump can and should be treated as part of a conservation program if the device is installed in lieu of a less efficient electric resistance heater. If the incentive induces the installation of an electric heat pump instead of gas space heating, however, the program needs to be considered and evaluated as a fuel substitution program."[19]

The SPM also emphasizes the "total energy supply system" perspective that is taken in the TRC and Societal Cost tests. This perspective is critical to efficient electrification assessment:

> "For fuel substitution programs, the test measures the net effect of the impacts from the fuel not chosen versus the impacts from the fuel that is chosen as a result of the program. TRC test results for fuel substitution programs should be viewed as a measure of the economic efficiency implications of the total energy supply system (gas and electric)."[20]

Thus, the California SPM was designed with electrification-like programs in mind. It should be noted, however, that the SPM tends to emphasize switching between electricity and natural gas in its discussion of fuel substitution programs. The SPM concepts are similarly applicable to switching between other fuels, such as switching from gasoline to electricity in the transportation sector.

Myth #2: The SPM only considers electricity bill impacts

Consistent with its accounting for multiple fuels as described above, the SPM considers impacts on total energy bills from a customer standpoint. The SPM does not just focus narrowly on electricity bill impacts.

The Participant Test, for example, includes a measure of the "avoided bill for the alternative fuel" in its quantification of the participant benefits of an efficient electrification program.[21] The description of the TRC and Societal Cost tests explicitly acknowledges that "the costs also include the increase in supply costs for the utility providing the fuel that is chosen as a result of the program."[22]

Myth #3: The SPM prescribes a specific methodology for quantifying avoided costs

The SPM defines a useful set of cost-effectiveness test perspectives and establishes the appropriate costs and benefits to be included to accurately capture each perspective. The SPM does not, however, dictate a precise methodology for calculating the benefits of a demand-side program.

Some in the industry have expressed frustration with the way costs and benefits are calculated in DSM proceedings, and have assigned this frustration to perceived flaws in the SPM. It is important to recognize that the SPM is not the source of these methodological decisions. The precise method for calculating benefits and costs is typically determined between utilities, regulators, and stakeholders on a state-by-state basis. For instance, the CPUC has developed multiple supplemental reports laying out protocols for quantifying costs and benefits of DSM programs.[23]

Myth #4: The SPM's results are driven by a focus on environmental externalities

The Societal Cost Test (SCT) is the only SPM test that includes all environmental externalities. And in the SCT, environmental impacts are weighed against a broad list of other costs and benefits. As discussed later in this section, the SCT accounts for avoided resource cost across the energy supply chain, employment impacts, and changes in quality of service, among many other factors. Environmental impacts are not given higher or lower priority than these other factors – all are considered on a level playing field.

Myth #5: The SPM requires that demand-side programs reduce source energy BTUs

The SPM provides a framework for determining if the benefits of a given program outweigh the costs. It does not include an explicit requirement related to energy consumption. The impact of a pro-

[18] "California Standard Practice Manual," California Public Utilities Commission, October 2001, 2-3.
[19] Ibid., page 3.
[20] Ibid., page 18.
[21] Ibid, p. 11.
[22] Ibid, p. 18.
[23] California Public Utilities Commission. "Energy Efficiency Portfolio Report." May 2018.

gram on net energy use only affects the benefit-cost equation to the extent that changes in net energy use increase or decrease costs and benefits. None of the SPM tests require that a program provide a prescribed change in energy use to pass.

There have been policies, such as California's "Three-Prong Test," which do include this requirement. However, those policies were developed outside of the SPM and exist independently of it (see the sidebar at the end of this section for further discussion).

What Makes Efficient Electrification Unique from a Cost-Effectiveness Standpoint?

Our conclusion that the SPM is relevant and applicable to efficient electrification may be a surprising finding to some readers. Historically, use of the SPM has been dominated by its application to energy efficiency programs, which have accounted for the vast majority of utility "demand-side" spending and have thus been the focal point of cost-effectiveness analysis. Energy efficiency programs at the state level have traditionally been focused on energy (kWh) reduction as the primary performance metric. As a result, in many people's minds the SPM has implicitly become narrowly associated only with its application in an energy efficiency context.

Being constrained to an "energy efficiency mindset" can result in missing important costs and benefits when applying the SPM to efficient electrification. For instance, energy efficiency programs commonly involve improving the efficiency of a single end-use appliance, without any need to consider the implications of fuel switching. It is necessary to unlearn some of the habits to appropriately apply the SPM to all forms of energy efficiency inclusive of efficient electrification.

Table 4 summarizes important differences between energy efficiency and efficient electrification programs, and the implications of these differences for cost-effectiveness assessment. Awareness of these implications is an important first step in applying the SPM to electrification programs.

Table 4. Comparison of Energy Efficiency and Efficient Electrification

Electric Energy Efficiency Program Features	Efficient Electrification Program Features	Implications for Cost-Effectiveness Assessment of Efficient Electrification
Reduces electricity consumption	Increases electricity consumption	Electrification programs do not present the same risks of cost under-recovery due to a reduced electricity sales base that is observed in energy efficiency programs. Alternatively, in the case of fuel switching, electrification increases risk of rate increase for alternative fuels. Consideration of non-electric bill impacts is important in this regard.
Impacts only one fuel type	Often involves fuel switching	Cost-effectiveness analysis cannot be limited to cost implications for a single utility or fuel type; must analyze costs and benefits across industries
Provides static (i.e., non-dispatchable) energy savings	Adds potentially flexible load	The value of load flexibility must be accounted for in an assessment of the potential benefits of electrification
Provides environmental benefit regardless of carbon-intensity of generation	Provides particular environmental benefit where generation is less carbon-intensive	Must account for future decarbonization of the power supply mix when evaluating environmental benefits; static assumptions are not sufficient
Reduces future need for electricity infrastructure	Increases need for electricity infrastructure; may reduce future need for alternative fuel infrastructure	Analysis must account for net change in infrastructure costs across industries, including stranded assets in non-electricity industries

Recommended Perspective: The Total Value Test

Overview

Among the various cost-effectiveness test perspectives defined in the SPM, the SCT is the most aligned with our recommended framework for evaluating efficient electrification programs. The SCT is the only cost-effectiveness test that explicitly and comprehensively accounts for the unique features of electrification programs. Such features include potentially significant non-energy benefits and changes in environmental externalities, in addition to core customer benefits.

At the same time, the SCT has developed a reputation for being too "open ended" and allowing for a subjective interpretation of which benefits and costs to quantify and include in the assessment. The SCT also uses a low "societal discount rate" which, by putting significant weight on longer-term benefits, tends to be very generous to new demand-side programs.

To mitigate these concerns about the SCT, we propose a revised test known as the **Total Value Test (TVT)**. The TVT uses the higher discount rate of the TRC test, based on the utility's weighted average cost of capital, but also includes the non-energy benefits and costs that are included in the SCT.

The TVT takes the broadest possible perspective on the costs and benefits of efficient electrification programs. While environmental impacts and non-energy benefits are important considerations, the TVT weighs them against similarly important changes in energy resource costs and other benefits that may accrue directly to participants and/or non-participants. An advantage of the TVT is that it comprehensively accounts for all possible sources of value, rather than taking a narrow perspective that may exclude important considerations.

Guidelines for Applying the TVT to Efficient Electrification Programs

The TVT is challenging to implement accurately and comprehensively. Implementation requires quantifying difficult-to-estimate benefits that extend beyond the realm of avoided utility resource costs. The implementation challenges are amplified when applying the test to nascent electrification programs with uncertain impacts that extend across multiple segments of the economy. In this light, the following are practical guidelines in five critical areas of implementation.

1. Identifying costs and benefits

Assessing the cost-effectiveness of efficient electrification programs begins with establishing a comprehensive list of cost and benefits. Table 5 is a list of possible costs and benefits included in the TVT. The applicability of each element should be viewed within the specific context of the program that is being evaluated.

An example is provided for each element. Throughout the table, we present examples for a range of fuels to illustrate that the impacts of efficient electrification programs typically extend significantly beyond the electricity sector.

Table 5 also provides the authors' perspective on the certainty with which each category of benefit and cost can be quantified. Some costs and benefits can be included in cost-effectiveness analysis with more confidence than others, depending on the data and resources available to conduct the analysis as well as the extent to which there is an established methodology for quantifying the impact.

The benefit and cost categories in Table 5 are primarily derived from two excellent resources. The first is a primer on energy efficiency cost-effectiveness assessment by Jim Lazar and Ken Colburn of the Regulatory Assistance Project (RAP), titled "Recognizing the Full Value of Energy Efficiency."[24] The second is the National Efficiency Screening Project's "National Standard Practice Manual," which provides guidelines for cost-effectiveness analyses that are tailored to the objectives of individual states.[25]

There is a nuanced difference between Table 5 as it appears here, and similar tables that have been developed previously in the context of energy efficiency analysis. Energy efficiency analysis focuses heavily on comparing program costs to the benefits of avoided production costs in the electricity system. Changes in the costs of non-electricity energy sources are typically given secondary consideration. However, in evaluating efficient electrification, any given category of system impacts should be quantified as a net change in costs across the multiple fuel systems that are being affected by the program. The change could be either a net cost or a net benefit. Thus, the examples in the table illustrate how the categories present the possibility of either a net societal cost or benefit.

[24] Jim Lazar and Ken Colburn, "Recognizing the Full Value of Energy Efficiency (What's Under the Feel-Good Frosting of the World's Most Valuable Layer Cake of Benefits)," Regulatory Assistance Project, September 2013.
[25] Tim Woolf et al., "National Standard Practice Manual for Assessing Cost-Effectiveness of Energy Efficiency Resources, Edition 1," National Efficiency Screening Project, May 18, 2017.

Table 5. Costs and Benefits of Efficient Electrification in the Total Value Test

Category	Example	Quantifiability
Program costs		
Administration costs	Marketing, measurement & verification	◓
Incentive payments	Rebates for equipment purchases	◓
Participant contribution to costs	Cost to consumer of equipment, net or rebate	◓
Third-party contribution to costs	Trade ally contribution to marketing costs	◓
System impacts		
Production capacity costs	New electricity generation peaking capacity	◓
Production energy costs	Reduced need for gasoline to power vehicles	◓
Cost of environmental regulations	Reduced gas utility compliance fees due to lower demand	◓
Fuel transmission capacity costs	Reduced need for natural gas pipeline expansion	◓
Fuel distribution capacity costs	Increased need for electric distribution capacity	◓
Line losses	Higher electricity line losses due to higher volume of sales	◓
Ancillary services	Provision of frequency regulation from new sources of flexible load	◓
Risk to the utility	Increased risk of stranded natural gas assets	◑
Renewable resource obligation	Higher RPS requirement due to higher electricity sales	◓
Energy market price effect	Increased wholesale electricity price due to peak demand growth	◑
Participant impacts		
Other resource costs	Increased water demand for hydroelectric power	◑
O&M costs	Elimination of need for regular oil changes for a gasoline vehicle	◑
Health impacts	Reduced medical costs	○
Productivity	Reduced product spoilage/defects	◑
Asset value	Improved property values	○
Economic well-being	Reduced foreclosures	○
Comfort	Vehicle noise reduction	○
Societal impacts		
Air quality	Reduced tailpipe emissions from gasoline vehicles	◑
Employment	Vendor/contractor staffing changes	◑
Economic development	Changes in gross domestic product	◑
Energy security	Reduced dependence on fuels from unstable regions	○
Public health	Reduced health insurance costs due to cleaner air	○

Key

Well established methodology, easily obtainable data

Less established methodology or difficult/costly to obtain data

Speculative, subject to high degree of uncertainty

"Quantifiability" represents the extent to which there is a well-established methodology for quantifying the impact, data is readily obtainable at a low cost, and there is limited uncertainty in the results

2. Non-energy costs and benefits

Non-energy costs and benefits – broadly defined as any societal- or participant-level benefit beyond energy savings – are an important consideration for efficient electrification. However, these impacts are also notoriously difficult to quantify.

There is a substantial literature on the measurement of non-energy benefits (NEBs) done in the context of energy efficiency and related programs. A recent review of studies available online identified nearly 300 papers concerning NEBs that have been authored since the early 1990s.[26] In this domain, categories of benefits include operations and maintenance ("O&M") cost savings, environmental impacts and associated public health benefits, participant health impacts, gains in employee productivity, changes in property values, benefits for low-income customers, economic development and improved comfort levels.[27] Of course, not all of these benefits are applicable to electrification programs, and others may exist. A recent LBNL study on the electrification of buildings and industry included balance of trade for fuels, energy security, potential reduction of fuel price risk, and process improvements in industry as additional potential benefits.[28]

The approaches used to quantify NEBs in energy efficiency and related programs vary according to the type of NEBs being quantified. However, three key categories or types of analyses can be identified:[29]

- *Engineering or model-based estimates:* For example, concentration-response models are used to convert avoided emissions into reductions in healthcare costs.[30] Similarly, economic development models such as IMPLAN can be used to quantify local economic impacts such as job creation.[31] In addition, the EPA's Regulatory Impact Assessments provide guidance on cost-benefit calculations to quantify health benefits.[32]
- *Incremental Incidence estimates*: These consist of applying factors from secondary sources to monetize benefits. For example, in the current context, avoided time spent getting oil changes might be valued at the marginal wage rate in a locality.
- *Survey-based analysis*: Survey methods, including contingent valuation, is used in the EE context to measure results related to comfort, for example. In the current context, one could envision the use of these methods to quantify benefits from vehicle noise reduction, for example.

The rigor of studies of NEBs associated with EE and related programs is highly variable. Common critiques include reliance on dated assumptions and inputs[33] and wide uncertainty in NEB estimates.[34]

However, several best practices have emerged. When properly applied, quantification of NEBs can be rigorous and reliable. Primary considerations include:[35]

- While the term NEB (or the closely-related Net Energy Impacts) is commonly used, rigorous studies seek to identify net NEBs, acknowledging that some of the non-energy impacts may be negative on balance.
- It is also crucial that any quantification of NEBs avoid double-

[26] See: Michael Freed and Frank A. Felder, "Non-energy Benefits: Workhorse or Unicorn of Energy Efficiency Programs?" *The Electricity Journal* 30 No. 1 (2017): 43-46,doi:10.1016/j.tej.2016.12.004. See also: Lisa A. Skumatz, "Non-Energy Benefits / Non-Energy Impacts (NEBs/NEIs) and their Role & Values in Cost-Effectiveness Tests: State of Maryland Final Report," Prepared for The Natural Resources Defense Council, Inc. (NRDC), March 2014, which provides an overview of the history and current status of NEB measurement.

[27] See, for example, Jim Lazar and Ken Colburn, "Recognizing the Full Value of Energy Efficiency (What's Under the Feel-Good Frosting of the World's Most Valuable Layer Cake of Benefits)," Regulatory Assistance Project, September 2013, 47-49. See also: Tim Woolf et al., "National Standard Practice Manual for Assessing Cost-Effectiveness of Energy Efficiency Resources, Edition 1," National Efficiency Screening Project, May 18, 2017, 54-58.

[28] Jeff Deason et al., "Electrification of Buildings and Industry in the United States: Drivers, Barriers, Prospects, and Policy Approaches," Lawrence Berkeley National Laboratory, Prepared for the Office of Energy Policy and Systems Analysis, U.S. Department of Energy March 2018, 4-6.

[29] Lisa A. Skumatz, "Non-Energy Benefits / Non-Energy Impacts (NEBs/NEIs) and their Role & Values in Cost-Effectiveness Tests: State of Maryland Final Report," Prepared for The Natural Resources Defense Council, Inc. (NRDC), March 2014, 20.

[30] Michael Freed and Frank A. Felder, "Non-energy Benefits: Workhorse or Unicorn of Energy Efficiency Programs?" *The Electricity Journal* 30 No. 1 (2017): 44, doi:10.1016/j.tej.2016.12.004.

[31] IMPLAN is one of several models that are widely utilized in the analysis of economic impacts. These models begin with a direct effect (such as an expenditure or new jobs) and, using input-output tables, estimate an ultimate economic impact that also includes indirect and induced effects.

[32] https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/regulatory-impact-analyses-air-pollution.

[33] Freed and Felder note that some recent program evaluations cite quantifications of benefits from the early 1990s.

[34] (Freed and Felder 2017, 45); (Skumatz 2014, 31-32).

[35] This discussion of best practices relies in part on (Skumatz 2014, 62-65) and on Bruce Tonn, et al., "Health and Household-Related Benefits Attributable to the Weatherization Assistance Program," Oak Ridge National Laboratory (2014). The latter is a recent example of a well-structured and rigorous analysis of NEBs. It relies in large part on literature reviews and extensive household surveys to estimate health and other household benefits.

counting.[36] For example, each unit of avoided consumption of carbon-based fuels could result in less mining and extraction (potentially generating environmental benefits), or it could result in increased exports of those fuels. However, it would be incorrect to count both.

- Begin with a well-defined scope and framework. Too frequently, quantification of NEBs appears to be an afterthought addressed only after energy-related benefits are satisfactorily quantified.
- Use existing literature to cross-validate results, particularly with respect to survey data. While surveys can be an effective way to collect data on multiple types of NEBs that can either only or most readily derived from user perceptions, it is important to compare these results with values derived from other studies and/or methodologies in order to have increased confidence in the results.

In the analyses of energy efficiency programs, non-energy benefits can be substantial, ranging from 50-400% of the energy benefits from those programs. The relative importance of NEBs in the calculation of cost effectiveness of electrification programs will depend in large part on the specifics of the program being evaluated. It is crucial that the quantification of any such benefits be done in a rigorous and reliable manner.

Non-Energy Benefits Evaluation in Practice

Washington, DC like several states, accounts for NEBs in cost-effectiveness screening for energy efficiency programs through the inclusion of an "adder." The DC Sustainable Energy Utility, which oversees energy efficiency programs throughout the District, uses a 10% adder for NEBs whenever the calculation would otherwise require significant original research. Screening also incorporates an environmental externalities adder (for example, this was $0.0713 per kWh in 2015).[37]

In **Massachusetts**, the Energy Efficiency Advisory Council recently commissioned a study that assessed and monetized eight health- and household-related NEBs experienced by recipients of energy efficiency services residing in income eligible households in MA. This study built upon and adapted the results of a national study of the Department of Energy's Weatherization Assistance Program, modifying and updating the inputs to better fit the Massachusetts context. The ultimate goal was to develop recommendations for integrating the results into the NEB estimates currently used by the Massachusetts program.[38]

The **Vermont** Public Service Board, relying on third-party research supporting the value of NEBs, ordered a 15% NEB adder, plus an additional 15% low-income adder when applicable, both of which are incorporated into cost-effectiveness screening of EE investments in Vermont.[39]

Ameren Missouri recently filed a proposal for a new beneficial electrification ("BE") program with the Missouri Public Service Commission. One aspect of the BE program includes incentives and support to encourage adoption of qualifying electric technologies, such as forklifts and airport ground support equipment. Expert testimony filed in support of this program did not seek to quantify, but explicitly cited non-energy benefits including (i) improvements in workplace safety, cleanliness, and noise levels; (ii) improved productivity; (iii) reduced maintenance costs; (iv) reduced exposure to fossil fuel price volatility; and (v) broader environmental benefits through reduced emissions of CO_2, NO_x, and particulate matter.[40]

[36] Tim Woolf et al., "National Standard Practice Manual for Assessing Cost-Effectiveness of Energy Efficiency Resources, Edition 1," National Efficiency Screening Project, May 18, 2017, 57.

[37] Ingrid Malmgren and Lisa A. Skumatz. "Lessons from the Field: Practical Applications for Incorporating Non-Energy Benefits into Cost-Effectiveness Screening." *ACEEE Summer Study on Energy Efficiency in Buildings* Volume 8 (2014): 186-200. Also, Richard Hasselman et al., "Evaluation of the District of Columbia Sustainable Energy Utility: FY2016 Annual Evaluation Report for the Performance Benchmarks (Final Draft)," Prepared for the District of Columbia Department of Energy and Environment, June 2017.

[38] Beth A. Hawkins et al., "Massachusetts Special and Cross-Cutting Research Area: Low-Income Single-Family Health- and Safety-Related Non-Energy Impacts (NEIs) Study," Prepared for Massachusetts Program Administrators, August 2016. Also, Bruce Tonn, et al., "Health and Household-Related Benefits Attributable to the Weatherization Assistance Program," Oak Ridge National Laboratory (2014).

[39] "Order Re: EEU Avoided Costs for 2016-2017 Time Period," State of Vermont Public Service Board, December 22, 2015. http://puc.vermont.gov/sites/psbnew/files/doc_library/order-re-eeu-avoided-cost-2016-2017.pdf.

[40] See: Direct Testimony of David K. Pickles, on behalf of Union Electric Company, Missouri Public Service Commission, File No. ET-2018-0132, February 22, 2018.

3. Accounting for policy goals

Policy goals have direct implications for cost-effectiveness analysis. Cost-effectiveness analysis that is conducted without consideration for policy goals will not produce conclusions that are useful for decision-making.

For instance, certain policies establish an economy-wide carbon reduction requirement. There will be a cost associated with meeting this requirement. From a cost-effectiveness standpoint, the relevant question is whether the proposed efficient electrification program will increase or decrease the all-in cost of satisfying the requirement.

Therefore, the impacts of established policies should be accounted for in the baseline scenarios against which the electrification program is being compared. In other words, the baseline scenario should reflect the costs and market dynamics associated with the achievement of policy goals. The proposed electrification program can then be evaluated on the basis for which it increases or decreases costs under these conditions.

To illustrate this concept, consider a utility proposal to provide rebates on the purchase of home EV chargers to spur adoption of EVs, which, in turn, will reduce carbon emissions. If this program is proposed in a state with a carbon emissions reduction goal, the costs and benefits of the proposed EV charging program need to be evaluated relative to the costs and benefits of alternative approaches that would need to be implemented to achieve the carbon reductions, rather than making the comparison to a world in which the carbon reductions are not achieved.

4. Defining the TVT "boundary"

A defining feature of the TVT is its treatment of subsidies. A literal interpretation of the Societal Cost Test, for instance, would not allow available subsidies to count as a net reduction in costs associated with the electrification program. The reason for this is, from a net societal perspective, subsidies to program participants are a cost to non-participants (e.g., through tax payments). The two cancel each other out in the TVT.

Other tests, such as the TRC test, would allow federal subsidies to reduce the costs that are considered in the cost-effectiveness evaluation. For instance, there is currently a federal tax credit of $2,500 to $7,500 available for the purchase of a new EV.[41] In a program designed to promote EV adoption, the TRC test would allow this credit to reduce the total quantified cost of the vehicle.

Utilities and state regulators may wish to define the boundaries of the TVT at the state level. As a practical consideration, doing so would allow federal subsidies to be included as a benefit (i.e., cost reduction) in the program. This approach has been taken by some utilities in electrification program applications.[42]

5. Near-term versus long-term costs and benefits

It is important to evaluate the cost-effectiveness of efficient electrification programs over a long-term study horizon. There are several reasons for this.

The benefits of electrification programs may extend well beyond the life of the equipment directly associated with the program. Consider, for instance, a utility proposal to develop a network of high-speed charging stations along rural interstates. In the near term, the cost of the program may exceed the benefits, when EV adoption is low and the charging stations are underutilized. But if the program allows customers to overcome concerns about range anxiety, then in the medium-term the program could promote growth of the EV market to a point where benefits of EV adoption exceed the costs of the charging station network. In the long-term, those charging stations will need to be replaced as they reach the end of their useful life. Yet, a portion of the ongoing benefits of the maturing EV market would be attributable to the contribution of the original charging program to overcome pre-existing barriers.

Electrification programs may also drive down technology costs over time. Consider the aforementioned high-speed charging infrastructure example. Utility development of the initial charging station network could cause EV adoption – and demand for charging stations – to cross a threshold point at which it makes economic sense for competitive providers of charging infrastructure to compete in the market. Economies of scale and the benefits of competition could drive cost reductions and technological improvements that extend well beyond the immediate impact of the utility program.

On the cost side of the analysis, there is also the possibility of stranded costs associated with the fuel that was replaced by electricity. For instance, a large-scale shift to high speed "fueling" of EVs

[41] The credit varies depending on the size and battery capacity of the vehicle.

[42] See, for instance, "Transportation Electrification Plan," Portland General Electric, December 2016, Submitted to Public Utility Commission of Oregon, December 27, 2016.

at public charging stations would result in less utilized gas stations, the costs of which would still be borne at the societal level. Stranded costs in non-electric energy sectors would have a negative near-term impact on the overall cost-effectiveness of electrification programs. However, the longer-term avoided need to maintain and replace these assets should be accounted for in the assessment. For example, in the case of under-utilized gas stations, the land could be sold or repurposed for higher-value uses.

A distinction should be made between stranded costs for regulated gas utilities versus stranded costs for non-regulated fuel providers of petroleum, propane, etc. The stranded costs of a regulated utility – which has an obligation to serve – are generally recoverable through the regulatory process. However, stranded costs on non-regulated fuel providers are non-recoverable – at least not in full – since companies in these competitive industries assume inherent risks in their business model.

Ultimately, the impact of these long-term considerations on the cost-effectiveness assessment is determined in part by the discount rate that is used. In the context of the TVT, a utility's weighted-average cost of capital (WACC) is recommended, since it is referenceable, non-arbitrary, and can be uniformly applied to all costs and benefits. We recognize that in practice, this places less emphasis on the longer-term impacts of electrification programs than does the SCT, which uses a lower societal discount rate. However, this low societal discount rate is often cited as a drawback to the practical application of the SCT. The use of the utility WACC as the discount rate, while accounting for the full spectrum of benefits and cost attributable to efficient electrification (or indeed any form of energy efficiency), is seen as a reasonable compromise that is practical to implement.

Do the "Other" Tests Matter?

While the TVT closely resembles the SCT and is the preferred cost-effectiveness perspective for efficient electrification programs, additional test perspectives are secondarily relevant. This section discusses the applicability of the other established tests.

Ratepayer Impact Measure (RIM) Test

The RIM test summarizes impacts from the short-term perspective of billpayers. In the context of electrification, it considers the net impact on the average customer's energy bills. In other words, if a program increases the average customer's electricity bill but decreases the natural gas bill, the RIM test considers the aggregate change across the two bills. Note that the RIM test applies to the average customer and is not just limited to bill impacts for participants in the program.

From a policy standpoint, it is important to consider the distributional impacts of efficient electrification programs. Some industry stakeholders have expressed concerns about the implications of efficient electrification programs for low-income customers. For instance, customers who cannot afford to pay the premium for an EV would effectively be ineligible for many EV-related programs. Policymakers may wish to look specifically at the implications of an electrification program for the energy bills of low-income consumers and other relevant customer segments.

In this regard, it would be appropriate to modify the RIM test to analyze impacts on specific relevant sub-segments of customers. A more detailed view of the distribution of bill impacts – both in the near term and in the longer term – would add value to the test as it is currently defined in the SPM.

Total Resource Cost (TRC) Test

The TRC test limits the "boundaries" of the test to customers within the utility system. As such, the TRC excludes impacts on customers in other service territories and non-utility customers, as well as externalities such as environmental impacts. This is generally an insufficient approach for comprehensively assessing the costs and benefits of efficient electrification.

Practitioners may wish to start with the TRC test, as it focuses primarily on those costs and benefits that are easier to quantify. But at the minimum, an awareness of the societal impacts not captured by the TRC test is necessary before making decisions based solely on this test.

It is worth noting that a focus on utility resource costs is entirely sufficient in other contexts, such as ratemaking, where rates are designed to reflect and collect only those cost incurred by the utility.

Program Administrator Cost (PAC) Test

The PAC test is largely irrelevant in the context of efficient electrification, as it does not account for costs and benefits that extend beyond the scope of the organization implementing the program. This deficiency is recognized in the California SPM, which acknowledges that the test "cannot be used to evaluate load building programs."[43]

[43] "California Standard Practice Manual," California Public Utilities Commission, October 2001, 24.

Participant Test

As with its use in other DSM initiatives, the Participant Test is primarily useful for determining program design, and for assessing the likely participation rate for customers in the program. Including the Participant Test perspective in a cost-benefit analysis also provides an indication of the extent to which net benefits to society of an efficient electrification program are accruing to those participants in the program who are enabling the benefits.

Resource Value Test

The Resource Value Test is not included in the California SPM. It was developed subsequently by the National Efficiency Screening Project and has received industry support as an overall framework for establishing a cost-effectiveness test that is consistent with local policy objectives.

The Resource Value Test is a set of guidelines for conducting a cost-effectiveness assessment. Unlike the California SPM it does not define a specific framework. By contrast, the objective of our study is to recommend a specific framework for evaluating the cost-effectiveness of efficient electrification. This requires making a specific declaration of what is "in" and what is "out" with respect to costs and benefits. As discussed above, the TVT is the most comprehensive perspective in this regard. However, we recommend reviewing the National SPM particularly for implementation guidance, as it addresses in useful detail several issues that were beyond the scope of our study.

Revisiting the "Three-Prong Test"

Several states have policies which implicitly or explicitly prohibit utilities from offering incentive-based fuel switching or fuel substitution programs. Perhaps the most notable of these policies has been California's three-prong fuel substitution test (aka the "Three-Prong Test"), which requires that any fuel switching program satisfy the following criteria: (1) it is cost-effective according to the TRC and PAC tests, (2) it does not adversely impact the environment, and (3) it does not increase source-BTU fuel consumption.[44, 45]

It is important to recognize that the Three-Prong Test is not one of the SPM tests. Rather, it is a tool designed to promote specific policy objectives within the state. It exists entirely outside of the California SPM framework.

The first two conditions of the Three-Prong Test — cost-effectiveness and environmental benefit — are certainly valid policy considerations. However, the third criterion on total source energy use is ambiguous, since source energy reduction in isolation lacks context, is neither a cost nor a benefit, and does not account for the diversity of electricity generation sources. In practice, this third prong artificially prohibits the introduction of fuel substitution programs such as efficient electrification that have the potential to both reduce energy bills and improve the environment.[46]

The Three-Prong Test is not the only example of policies that effectively prohibit fuel switching. For instance, in Minnesota, utilities are not allowed to promote incentive-based fuel substitution programs.

Policies that prohibit fuel switching or substitution should be reconsidered in light of the cost-effectiveness framework established in this report. Rather than evaluating cost-effectiveness and environmental benefits as two separate criteria, the costs or benefits of changes in environmental conditions should be weighed against the costs and benefits of other relevant impacts in order to determine if the program is beneficial in the aggregate.

In August 2019, the California Public Utilities Commission (CPUC) issued a ruling to update the Three-Prong Test, designating the baseline for energy and emissions savings comparisons, and specifying carbon emissions as the primary measure of environmental impact.[47] This ruling is expected to spur utility investment in efficient electrification programs from ratepayer-funded energy efficiency budgets. The Total Value Test can be applied as a screening mechanism for regulators to determine which programs warrant ratepayer funding, and those screened programs can be further prioritized based on factors such as customer benefit.[48]

[44] "Energy Efficiency Policy Manual, Version 5," California Public Utilities Commission, July 2013.

[45] "Source BTUs" or "source energy" refers to the energy content of the fuel required to perform a given task. In the case of electricity, the source BTU calculation is based on assumptions about the fuel composition of the generators that supply electricity to the region.

[46] Seel, Alison. "Three Prongs Don't Make a Right." Sierra Club. April 27, 2018.

[47] "California Opens $1B in Efficiency Funding to Electrification." Utility Dive. August 2, 2019.

[48] "Order Instituting Rulemaking Concerning Energy Efficiency Rolling Portfolios, Policies, Programs, Evaluation, and Related Issues." California Public Utilities Commission. Rulemaking 13-11-005. April 26, 2018.

Case Studies

Introduction

To demonstrate the framework of the proposed Total Value Test (TVT), we conducted three case studies of potential electrification applications. The first case study explores electrification of city buses in a medium sized city. In the second case, we analyze the emerging sector of electrified indoor agriculture. The third case considers the relative benefits of a range of electric and gas water heating technologies. These case studies are designed primarily to illustrate the application of the proposed TVT framework to real-world electrification examples and could be expanded through future research to include additional costs and benefits, as well as other new technologies.

City Bus Electrification Case Study

Transportation electrification is an area of increasing focus as the costs of batteries decline, the availability of electrified models increases, and GHG emission reduction mandates become more stringent. Through this case study, we analyze the costs and benefits of a transit agency purchasing battery electric buses (BEB) as a replacement for diesel buses.

Electrifying city buses has several potential advantages over electrifying personal vehicles: buses maintain a high utilization rate by operating throughout the day, their daily and weekly duty cycles are consistent, and they have a central location for refueling or recharging. In addition, cities with long-term sustainability goals are likely to consider the broader environmental benefits that electric buses can provide, namely reductions in local air pollution and GHG emissions.

To make the case study broadly applicable, we analyze the costs and benefits of a transit agency in a medium sized U.S. city of roughly 1 million residents. The city is considering whether to continue purchasing diesel buses (i.e., the baseline scenario) or to instead purchase new BEBs (i.e., the electrification scenario). We assume that the transition of the fleet would occur according to a normal 12-year replacement schedule.[49] Existing diesel buses are assumed to continue to operate for the remainder of their life, after which they are replaced with electric buses. We assume that this city's transit agency operates a fleet of 180 buses, meaning the agency replaces 15 buses each year. We also assume that the transit agency will purchase BEBs with batteries large enough to allow replacement of diesel buses at a 1:1 ratio.[50] Finally, we assume the electric buses will be charged overnight by 120 kW DC fast chargers. See the Cost Benefit Analysis section of this section for further discussion of these and all other model assumptions.

Findings

As discussed earlier in this report, evaluation of efficient electrification should consider a wider range of costs and benefits than the tests currently applied to electric sector programs (e.g. energy efficiency initiatives). The costs and benefits that are most relevant to bus electrification are listed in Table 6.

Costs and benefits listed in Table 6 were quantified to demonstrate important considerations when applying the TVT, and to illustrate how the TVT differs from the Participant Test. Table 7 below shows the present values of costs and benefits under each test in the Western United States. Under the Participant Test, there is a **net cost of $0.7 million** when purchasing BEBs instead of diesel buses. Alternatively, the TVT indicates a **net savings of $5.7 million** for the same scenario. The discrepancy between these two values is a result of the TVT's different treatment of fuel costs and its inclusion of emissions-based externalities and electrical system upgrade costs. These costs are discussed in detail in the Cost Benefit Analysis section of this section.

In addition to the benefits and costs quantified above, a detailed evaluation of bus electrification would include consideration of various non-energy benefits. These factors are discussed qualitatively below. *A Framework for Evaluating Electrification Cost-Effectiveness* provides discussion of techniques for incorporating these difficult-to-quantify benefits.

- *Load growth and flexibility value:* Electrifying city buses provides the electrical system with consistent and predictable nightly load that may also generate additional flexibility benefits depending on charging needs and infrastructure capabilities.[51] Added flexibility can contribute to system reliability, facilitate greater integration of variable generation and generate revenue for transit agencies through participation in ancillary services markets.

[49] Transit agencies tend to retire buses after roughly 12 years in order to take advantage of federal subsidies for purchasing new vehicles.

[50] The battery size is assumed to be 440 kWh per bus.

[51] If buses are parked at the depot for longer than it takes to recharge them, they have some capability to provide ancillary services to the grid during their down-time.

Table 6. Costs and Benefits Categories of Electrifying City Buses

Cost/Benefit Type	Subcategories
Total Cost of Ownership	• **Vehicle and battery costs, replacement ratios, and lifespan** • **Fuel costs** and cost volatility • **Maintenance costs** • **Charging infrastructure costs** • Revenue generated by grid (V2G) services
Environmental Externalities	• **Greenhouse gas (GHG) emissions** • **Other air pollutant emissions** • Other public health impacts • Noise pollution
System Impacts of Increased Load	• **Local distribution upgrades** • **Impacts on system peak load** • Added grid flexibility[1] • Impact on electricity rates (savings to billpayers)
Additional Considerations	• Driver health/wellbeing • Customer benefits • Disaster relief • Energy security from reduced imports

Note: Bold items are quantified. Other items are discussed qualitatively.

[1] The daily duty cycle of city buses does not generally lend itself to serving grid flexibility needs, which are most acute during the morning through evening periods when the buses are assumed to be on the road. Grid flexibility needs are reduced at night, the time when the buses are plugged in for charging.

Table 7. City Bus Electrification Case Study Results for Illustrative City in Western U.S.

NPV of Costs and Benefits (2018 $)	Participant Test (Transit Agency's Perspective)	Total Value Test
Costs		
Capital Costs	$5.4 million	$5.4 million
Electricity Costs	$1.8 million	-
Generation Costs	-	$0.9 million
Local Distribution Upgrade Costs	-	$0.4 million
Benefits		
Diesel Cost Savings	-$5.6 million	-$4.3 million
Maintenance Cost Savings	-$0.9 million	-$0.9 million
Avoided GHG Emissions Impacts	-	-$0.2 million
Avoided Air Pollutant Impacts	-	-$6.9 million
Net Change in Costs	**$0.7 million**	**-$5.7 million**
Non-Quantified Impacts	Potential flexibility value and revenues, improved customer experience, reduced noise pollution, mobile emergency electricity supply services	

Note: Electricity rates, diesel costs, and electricity fuel mix are reflective of the Pacific coast states, including California, Washington, and Oregon. All values represent differences in costs and benefits associated with replacing 15 diesel buses with 15 electric buses. NPV figures include all costs and benefits incurred over the 12-year lifetime of the buses (2018-2029), calculated using an 8% discount rate.

- *Noise pollution*: Electric buses produce less noise pollution than equivalent diesel buses. Reduced noise results in a better experience for passengers and drivers as well as those who live or work near bus routes.
- *Customer benefits*: The drive train of an electric bus allows for smoother acceleration while the regenerative braking system yields more even deceleration. These attributes provide a more comfortable ride for passengers and drivers while potentially minimizing wear and tear on roads and bridges.
- *Disaster relief*: In addition to the added flexibility that buses can add to the electrical grid during charging hours, the energy stored in bus batteries could potentially serve as backup power for hospitals or other critical infrastructure during a natural disaster or major grid outage.
- *Energy security*: Electrifying transit reduces U.S. dependence on foreign oil while supporting domestically produced electricity.

Assumptions

Capital Costs: Analysis of fleet size and operations data from the Federal Transit Administration indicates that a transit agency serving a city of 1 million people likely owns around 180 city buses driving a total of 24,300 vehicle revenue miles (VRM) each day (average of 135 VRM per bus per day).[52] In the electrification scenario, we assume that the transit agency will purchase electric buses with batteries large enough to achieve a 1-to-1 diesel bus replacement ratio while still serving an entire day's route on a single charge (i.e. no opportunity charging).[53] Based on industry research and interviews with electric bus manufacturers, we analyzed a standard 40-foot electric bus with a 440 kWh lithium ion battery pack. Operating at an expected efficiency of 0.5 miles per kWh, this bus is capable of driving up to 220 miles per day, ample range to complete most if not all of a city's daily bus routes. This strategy avoids any major operational changes as well as the considerably higher costs of high-power opportunity charging infrastructure. A typical bus of this size and capacity costs roughly $750,000, of which $200,000 is the battery pack costs.[54] For reference, a typical 40-foot diesel bus costs roughly $450,000.

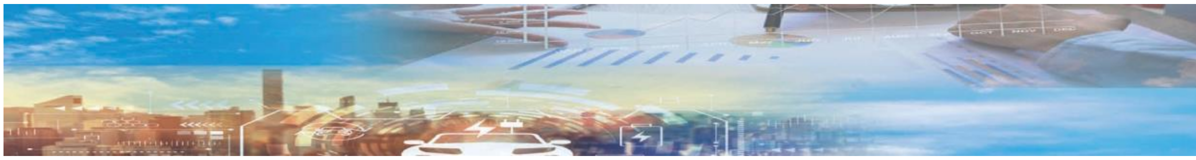
We assume the buses will be recharged overnight by 120 kW DC fast chargers, which each cost roughly $50,000 and can provided a full recharge in 3 to 4 hours. Due to the potential for charger-related outages, we assume the transit agency purchases 2 spare chargers for every 15 buses for a total of 17 chargers each year. Depending on the bus operating schedule, it is possible that smaller 60 kW chargers would suffice. However, the larger 120 kW chargers offer a greater assurance that the buses will be fully charged in time for the morning routes. A variety of future charging infrastructure ownership models is possible. In this model, we assume that the transit agency will purchase and operate the chargers. However, several recent regulatory filings (See the *Current Utility Practices* section of A *Review of Current Practices*) suggest that, in some jurisdictions, utilities will seek to invest in charging infrastructure. If the utility company purchases charging infrastructure instead of the transit agency, the capital costs within the Participant Test would decline significantly, but electricity rates would be expected to increase. The TVT would be unaffected by this change.

Fuel Costs: In contrast to their significantly higher capital costs, BEBs provide considerable savings in fuel costs and maintenance costs. We quantify expected fuel expenditures by predicting annual fuel consumption using expected miles driven and bus fuel efficiency and subsequently multiplying fuel consumption by forecasted fuel prices.

Using the assumed VRM of 135 miles per day per bus and a typical fuel efficiency of 4 miles per gallon for diesel and 0.5 miles per kWh for electric, we calculate annual fuel consumption of roughly 185,000 gallons for 15 diesel buses and 1.5 GWh for 15 electric buses.[55] The fuel cost savings vary by year and region, but on average the fuel expenditures in the electrification scenario were roughly one-third of the diesel scenario fuel costs ($0.29 per mile for electric, $0.87 per mile for diesel).

[52] Federal Transit Administration, 2002-2018, "June 2018 Adjusted Database," United States Department of Transportation, accessed August 29, 2018.
[53] Opportunity charging refers to rapid charging at bus stops or terminals during idle periods throughout the operating schedule.

[54] While the expected lifespan of an electric bus battery is likely less than the 12-year lifespan of the bus, electric bus manufacturers are starting to offer purchase alternatives (i.e. battery leasing, extended warranties) that eliminate the uncertainty of battery lifespan. The $200,000 figure quoted above represents a battery with a 12-year unlimited mile warranty.
[55] Hanjiro Ambrose, Alissa Kendall, and Nicholas Pappas, "Exploring the costs of Electrification for California's Transit Agencies," 45, Accessed August 29, 2018. Bloomberg New Energy Finance, "Electric Buses in Cities: Driving Towards Cleaner Air and Lower CO2," 32-34, Accessed August 29, 2018.



For the Participant Test, the cost of diesel is the price paid at the pump, whereas the cost of electricity is the applicable retail rate paid to the local utility. The TVT counts fuel costs differently. In the case of electricity, we assume that 50% of the average retail electricity rate is composed of generation costs, and 25% is composed of demand-driven investments in grid infrastructure necessary to meet the incremental load of the electric buses. The remaining 25% is assumed to contribute to the cost recovery for maintaining the existing transmission and distribution systems and reduces the cost burden on other billpayers. The costs of generation and system upgrades are included in the TVT, but the remaining 25% is not.

The TVT excludes this portion of electricity costs because while it is a cost to the transit agency, it offsets costs that would otherwise be incurred by other billpayers.

Similarly, in the case of diesel fuel, some portion (between 37 and 99 cents per gallon[56]) of total fuel costs is federal and state diesel fuel taxes which are primarily spent maintaining roads and infrastructure. Therefore, the fuel tax portion of the diesel cost constitutes a transfer payment and is excluded from the TVT. In this case study, we deduct the federal tax and the regional population-weighted average state tax from diesel costs for each region. This holistic treatment of diesel and electricity costs yields lower fuel costs under the TVT than the Participant Test for both scenarios.

Maintenance Costs: Diesel bus maintenance costs are generally well understood and predictable. However, maintenance costs for electric buses are more uncertain due to the nascent state of the industry. There is consensus across the industry that maintenance costs of BEBs are lower than those of diesel buses due to the simpler drive train and regenerative braking systems. However, the extent of those savings remains largely unknown. Some BEB manufacturers claim as high as 40% savings, but early analyses of pilot programs suggest more conservative savings. Our model assumes BEB maintenance costs are 20% lower than those of equivalent diesel buses.[57] Maintenance costs are treated identically by the Participant Test and the TVT.

Emissions Costs: The electrification and baseline scenarios of this analysis have vastly different costs of environmental externalities. And while the Participant Test does not explicitly internalize any of these externalities, projected damages caused by emissions are considered costs in the TVT.[58]

In this case study, we estimate emissions damages in two categories: climate-based damages from CO_2 emissions and public health damages from emissions of criteria air pollutants (CAPs). We value CO_2 damages according to the U.S. Government Interagency Working Group's estimates at a 5% discount rate of $11 to $18 per metric ton of CO_2 escalating between the years 2015 and 2035.[59] We estimate the cost of CAP emissions based on values sourced from existing literature.[60] Those values are $4.72 per gallon of diesel fuel, $0.19 per kWh from coal-fired generation, and $0.057 per kWh from natural gas-fired generation.

We use these estimated costs to calculate climate and public health damages from consumption of diesel fuel and electricity generation. This methodology is roughly consistent with the approach to valuing emissions damages in the Societal Cost Test. The fundamental distinction is that the future emissions damages in the TVT are discounted using a discount rate consistent with the cost of capital (8-10%) used to discount all other costs and benefits, rather than using a lower societal discount rate.

[56] Energy Information Administration, 2018, "Federal and State Motor Fuels Taxes[1]," United States Department of Energy, August 2018, Accessed August 29, 2018.

[57] California Air Resources Board, *Advanced Clean Transit Program Literature Review on Transit Bus Maintenance Cost (Discussion Draft)*, (Sacramento, CA, 2016), accessed August 29, 2018.

[58] If emissions are priced through a Pigovian tax or an emissions trading scheme, the associated externalities are internalized to whatever extent the tax passes through to the end user (presumably through fuel prices). So if emissions are priced, the Participant Test does capture emissions damages but only to the extent that the transit agency is forced to pay for them. Since these costs generate revenue for the government (or profit for a separate, rent-seeking party), they constitute a transfer payment and a net-zero cost under the TVT. However, due to the relative rarity of substantial emissions taxes, these costs are not quantified in this model.

[59] For the social cost of carbon, we chose the value based on a 5% discount rate because it is closest to the discount rate of 8% assumed in our analysis. Interagency Working Group on Social Cost of Greenhouse Gases, "Technical Support Document – Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis – Under Executive Order 12866," United States Government, August 2016.

[60] Drew T. Shindell, "The Social Cost of Atmospheric Release," Climatic Change 130 no. 2 (February 25, 2015): 313-26, Accessed August 22, 2018, doi:10.1007/s10584-015-1343-0.

Indoor Agriculture Case Study

Indoor agriculture includes several types of enclosed environments for growing various types of produce, including warehouse farms, container farms, and enhanced greenhouses (which supplement natural sunlight). These environments rely on artificial light, climate control, and water delivery systems to grow produce on land and during seasons that are otherwise unsuitable for doing so.[61] In the U.S., there were over 40,000 indoor farms, mostly enhanced greenhouses, as of May 2017.[62] Indoor farms primarily target low-growing, short shelf-life, and high-value produce, such as berries, leafy greens, and herbs. Developers of indoor farms note that these facilities are not necessarily intended to be a perfect substitute for conventional farming, but can provide produce that is more nutritious, fresher, and locally grown compared to alternatives. In addition, indoor agriculture is a pathway to accommodate a growing population with constrained land resources.

In this case study, we analyze the costs and benefits of an indoor warehouse farm located in the Denver metro area. The farm is assumed to produce 5,000 pounds per week of leafy greens (e.g., spinach), which is the typical output of a 10,000 square foot indoor vertical farm. For comparison purposes, we analyze differences in the variable operating costs of producing warehouse-grown spinach versus organic spinach delivered from California.[63] Using the TVT as an evaluation framework, this case study demonstrates the issues a policymaker, regulator, utility, or other stakeholders would want to consider when developing policies that would facilitate growth in the nascent indoor agriculture industry.

As mentioned above, it is difficult to establish definitive tradeoffs between two types of agriculture, as it is unclear whether the indoor farm will displace local or imported produce and there is wide variation in potential unit-level energy consumption. As we explain below, we focus on a side-by-side comparison of the variable operating costs that are reasonably quantifiable, while acknowledging that consideration of other costs and benefits would be warranted when making policy decisions in this context.

Findings

Relevant benefits and costs of indoor agriculture are summarized in Table 8. With indoor agriculture, non-energy benefits are more prominent than energy benefits due to the complexity of the food production and delivery systems. This case study is useful for highlighting the extent to which the benefits and costs of electrification programs can extend well beyond the energy sector.

Annual variable costs of indoor and outdoor farms are compared using the TVT. Table 9 below shows the total annual costs and costs per pound of spinach for the components we quantified in the TVT. For the indoor farm, the TVT indicates a net annual cost decrease of $27,700, or $0.20 per pound of spinach sold, resulting in a benefit/cost ratio of 1.34.

[61] For an overview of the indoor agriculture industry, see: EPRI, "Indoor Agriculture: A Utility, Water, Sustainability, Technology and Market Overview," June 2018.
[62] Allison Kopf, "Let's Talk about Market Size," *Medium*, May 19, 2017, Accessed November 12, 2018.
[63] Roughly 70% of all spinach consumed in the US is grown in California. Brian Palmer, "What Would We Eat If It Weren't for California?" Slate Magazine, July 10, 2013, Accessed November 16, 2018.

Table 8. Cost and Benefit Categories of Indoor Agriculture

Cost/Benefit Type	Subcategories
Costs of Production	• **Electricity costs** • **Water costs** • **Land costs** • **Transportation costs (fuel, wages, maintenance)** • **Other fuel costs (farm equipment)** • Labor costs • Other capital costs (equipment and warehouse) • Fertilizer use and application • Land maintenance costs (weeding, tilling, crop cycling)
Environmental and Human Health Externalities	• **Greenhouse gas (GHG) emissions** • **Other air pollutant emissions** • **Public health impacts** • Environmental/agricultural damages • Groundwater depletion and salt Intrusion • Fertilizer runoff effects • **On-road accidents (shipping)** • Noise pollution (shipping)
System Impacts of Increased Load	• **Local distribution upgrades** • **Impacts on system peak load**
Additional Considerations	• Reduced food waste/loss along supply chain • Fresher and more nutritious produce • Year-round availability of seasonal crops • Reduced susceptibility to disease and inclement weather

Note: Bold items are quantified. Other items are discussed qualitatively.

Table 9. Indoor Agriculture Case Study Results

5,000 lbs/week spinach farm	Annual Cost			Cost per Pound (Delivered)		
	Indoor Farm	Outdoor Farm	Difference	Indoor Farm	Outdoor Farm	Difference
Electricity Cost	$23,000	$0	$23,000	$0.16	$0.00	$0.16
Land Rent Cost	$18,600	$34,000	-$15,400	$0.13	$0.24	-$0.11
Water Cost	$2,000	$9,900	-$7,900	$0.01	$0.07	-$0.06
Transportation Cost	$500	$33,300	-$32,800	$0.00	$0.24	-$0.23
On-Site Diesel Cost	$0	$8,700	-$8,700	$0.00	$0.06	-$0.06
GHG Emissions Impacts	$2,300	$1,000	$1,300	$0.02	$0.01	$0.01
Non-Carbon Externalities	$35,400	$22,600	$12,800	$0.25	$0.16	$0.09
Total	**$81,700**	**$109,400**	**-$27,700**	**$0.58**	**$0.77**	**-$0.20**

Note: Per-pound values are per pound of spinach that reaches the consumer, assuming 46% of harvested spinach is lost or wasted along the supply chain.[62] Electricity rates reflect the average of 2018 commercial and industrial rates for the Mountain and Pacific regions, based on EIA projections.[63] Diesel costs are reflective of the on-farm delivery of red dye (off-road) diesel in the central coast region.[64] We assume the current generation mix for PG&E and Xcel Energy Colorado.[65]

The electricity cost for the indoor farm is offset by lower land, water, and transportation costs.[68] Due to the heavily fossil-based generation mix in Denver, which consists of 44% coal and 28% natural gas, the indoor farm has higher emissions-related costs. As we explain further below, the costs of the indoor farm are very sensitive to the assumed efficiency of the indoor facility; the costs shown here are based on a highly efficient indoor farm that consumes about 7 MWh per week to produce 5,000 lbs. of spinach.

In addition to the benefits and costs quantified above, a detailed evaluation of indoor agriculture could include consideration of the capital costs of building the indoor farm and various additional components. These factors are often difficult to quantify due to lack of accurate information on the potential scale and value of the impacts.

- *Nutritional Value:* More locally grown produce will increase the nutritional value of leafy greens like spinach because nutritional value tends to decrease with increased time between harvesting and consumption.[69]
- *Additional Benefits of Reduced Water Demand:* The reduction in water demand could have greater benefits in regions that are experiencing extreme drought conditions. The reduced water demand will also limit salt intrusion of existing water supplies.[70]

[64] USDA Economic Research Service, 1970-2017, "Loss-Adjusted Food Availability, Vegetables," United States Department of Agriculture, Accessed November 2, 2018.
[65] Energy Information Administration, 2018-2050, "Annual Energy Outlook 2018: Energy Prices by Sector and Source" ("EIA, 2018"), United States Department of Energy, accessed November 7, 2018.
[66] Laura Tourte, et al., "Sample Costs to Produce and Harvest Organic Spinach, Central Coast Region," Department of Agriculture and Resource Economics, University of California Cooperative Extension, 2015, Accessed November 2, 2018. ("Tourte et al., 2015").

[67] Xcel Energy, *Colorado Energy Plan Fall 2018 Update - Information Sheet,* 2018, accessed November 2, 2018. Pacific Gas & Electric, *Exploring Clean Energy Solutions*, 2018, accessed November 02, 2018.

[68] The costs for operating electric water pumps for the outdoor farm are included in the water costs.

[69] Luke F. Laborde and Srilatha Pandrangi, "Retention of Folate, Carotenoids, and Other Quality Characteristics in Commercially Packaged Fresh Spinach," *Journal of Food Science* 69(9) (December 1, 2004): 702-707.
[70] Julie Nico Martin, "Central Coast Groundwater: Seawater Intrusion and Other Issues," CA Water Plan Update 2013 (4) (August 4, 2014): 1-27.

- *Reduced Fertilizer Run-off:* The environmental impact of fertilizer run-off are well documented but are very specific to the conditions of the local terrain and waterways.[71]
- *Food Security:* Indoor farming could also increase food security by reducing the potential for disease outbreak through the food supply and reducing food imports.[72]

Assumptions

Energy Costs: Due to the electricity demands of growing crops with artificial lighting, electricity use is a significant operating cost for indoor agriculture. Due to differences in efficiency, crop arrangement, and climate, electricity use varies widely across indoor farms. A typical warehouse farm of this size is expected to consume between 7-70 MWh of electricity per week (1.4-14.0 kWh per pound grown) for lighting and HVAC systems.[73] As noted above, we assume a highly efficient indoor farm that consumes 7 MWh per week (365 MWh per year or 1.4 kWh per pound grown). We estimate the electricity costs based on the projected industrial electricity rate of 8.4 cents per kWh, which totals $31,000 per year.[74] As in the electric bus case study, we assume that approximately 50% of the retail electricity rate covers the cost of incremental generation and that 25% of the rate serves as a proxy for the costs of local distribution system upgrades to serve the incremental load. The remaining 25% of the retail rates covers cost of recovery for existing infrastructure that would otherwise be paid by other billpayers.

The outdoor farm electricity use is primarily for water pumps. We estimate that the outdoor farm consumes 8 MWh per year for pumping groundwater, assuming 8.8 acre-inches of water per acre per harvest (10 million gallons per year), water table depth of 120 feet, and pump efficiency of 48%.[75]

The outdoor farm consumes diesel for operating its equipment and shipping its products to market. We estimate that the outdoor farm uses about 3,000 gallons per year of diesel, assuming on average 76 gallons of diesel fuel per acre per harvest.[76] At an assumed price of $2.86 per gallon, this fuel costs roughly $9,000 per year.[77] In both scenarios, we assume that the spinach is shipped in 12-meter refrigerated trucks with fuel efficiency of 6.5 miles per gallon.[78] For the indoor farm located approximately 20 miles from the point of consumption, shipping requires just 50 gallons of diesel per year, whereas the outdoor farm located 1,300 miles from the point of consumption requires 3,000 gallons of diesel per year. The costs of transportation diesel are included in the shipping costs, but the externalities associated with the diesel consumption are separately included in the TVT and discussed further below.

Water Costs: Indoor farms use water much more efficiently than outdoor farm by capturing and recycling runoff. Like electricity use, estimates of the water consumption of indoor farms vary widely, ranging from an 80 to 99% reduction compared to outdoor farms.[79] For this case, we assume the indoor farm achieves a 95% reduction in water consumption. We estimate that the outdoor farm uses 350 acre-inches (10 million gallons) of water per year, or 37 gallons per pound of spinach grown. The price of pumped groundwater in the Santa Cruz region has fluctuated between $18 and $36 per acre-inch in recent years.[80] Assuming $27 per acre-inch, water for the outdoor farm costs $10,000 per year.[81] On the other hand, the indoor farm consumes 18 acre-inches (480,000 gallons) of water per year or 1.8 gallons per pound grown. Based on municipal water prices in Denver of $111 per acre-inch, the indoor farm spends $2,000 per year ($.007 per pound grown) on water. Even with the significantly more expensive municipal water, the indoor farm pays far less for water.

Land Costs: The indoor farm's efficient use of land reduces land costs, even with the higher cost of land closer to urban centers. For the indoor farm, we assume a floor area ratio (FAR) of 0.4, meaning the 10,000 square foot indoor farm requires a 25,000 square foot (0.57 acre) lot to produce 260,000 pounds of spinach per year. We estimate that renting an industrial lot of this size in the Denver metro area would cost roughly $19,000 per year.[82] The outdoor

71 Daniel J. Sobota, Jana E. Compton, Michelle L. McCrackin, and Shweta Singh, "Cost of Reactive Nitrogen Release from Human Activities to the Environment in the United States," *Environmental Research Letters* 10(2) (February 17, 2015): 1-13.
72 Purdy, Chase. "A Startup Is about to Build 300 Vertical Farms in China, Thanks in Part to Jeff Bezos." Quartz. January 26, 2018. Accessed November 15, 2018.
73 Frank Sharp, Senior Technical Leader at the Electric Power Research Institute, Telephone interview by author, October 23, 2018, ("Sharp, 2018").
74 EIA, 2018.
75 Tourte et al., 2015.
76 Tourte et al., 2015.
77 Tourte et al., 2015.
78 Brandon Schoettle, et al., "A Survey of Fuel Economy and Fuel Usage by Heavy-Duty Truck Fleets," American Transportation Research Institute, October 2016, Accessed November 2, 2018.
79 Sharp, 2018.
80 Tourte et al., 2015.
81 Note: the 25% of the underlying electricity costs (8 MWh per year at $100 per MWh) that is a transfer payment is subtracted from the price paid for water.
82 Kimmons (2018) estimates an average floor area ratio of 0.29-0.4 for commercial buildings. Albouy et al. (2018) estimate the average price of land in Denver to

farm requires roughly 13 acres to produce an equivalent quantity of spinach. The estimated cost of leasing agricultural land in the central coast is $2,400 per acre per year, resulting in land costs of $34,000 per year.[83]

Transportation Costs: By growing the spinach near the point of consumption, the indoor farm avoids significant shipping costs and the associated externalities. Assuming a shipping density of raw spinach of 279 lbs. per cubic meter[84] and a volume of 60.6 cubic meters for a 12-meter refrigerated truck,[85] we estimate that 5,000 lbs. of spinach each week will fill about a third of a delivery truck.[86] For the outdoor farm scenario, shipping 260,000 lbs. of spinach 1,300 miles from California to Denver requires a total of 20,000 truck-miles. For the indoor farm scenario, shipping the same weight of spinach a distance of 20 miles requires a total of 300 truck miles. At a marginal cost of $1.59 per truck-mile, the transportation cost for the outdoor farm is $33,000 per year.[87] The corresponding figure for the indoor farm is $500 per year. These figures only represent the variable costs of on-road transportation and do not include the fixed costs associated with loading, unloading, and planning the shipment. However, assuming both scenarios require the same number of shipments, those fixed costs are likely similar in both scenarios.

Public Health Costs: We use the same figures used in the city bus case study to estimate the damages from electricity generation and on-farm diesel consumption.[88] Based on the 3,000 gallons of diesel consumed on-site by the outdoor farm, the estimated damages of criteria air pollutants are $14,000 per year. The air pollution costs from electricity use vary significantly depending on how the electricity in a region is generated. Using the 2018 power mix for Santa Cruz County (20% natural gas, 80% clean) and Denver (44% coal, 28% natural gas, 28% clean), the air-pollution damages from electricity consumption are 0.7 cents per kWh in California and 10 cents per kWh in Denver. Based on these figures and the electricity consumed, the annual air pollution damages from electricity are $50 per year for the outdoor farm and $50,000 per year for the indoor farm.[89]

Based on existing literature, the costs of air pollution from delivery trucks has been estimated to be 1.9 cents per ton-mile, which corresponds to a 16 cents per truck-mile for a truck carrying a 17,000 pound load.[90] The costs of on-road injuries are estimated to be 25 cents per mile due to additional trucks on the road.[91] Combined, we estimate damages of $.41 per truck-mile, or $8,000 per year for the outdoor farm and $130 for the indoor farm.

Climate Costs: As in the city bus electrification case study, we estimate the social cost of carbon according to the U.S. Government Interagency Working Group's 5% discount rate values, which escalates from $11 to $18 per metric ton of carbon dioxide between the years 2015 and 2035. Based on the carbon intensity of diesel fuel, and electricity generated from coal and natural gas, we calculate the following annual carbon emissions: The indoor farm emits 229 tons per year from electricity use and 0.5 tons per year from diesel consumption, while the outdoor farm emits 0.7 tons/year from electricity use and 70 tons/year from diesel consumption. The resulting climate-related damages are $1,000 per year for the outdoor farm and $3,000 per year for the indoor farm.

be $539,000 per acre. Schnitkey (2016) calculates common land rental price to land price ratios. Applying a conservative ratio of 0.05, we calculate an annual land rent cost of $27,000 per acre. James Kimmons, "Learn How to Calculate the Land to Building Ratio," The Balance Small Business, September 9, 2018, Accessed November 21, 2018. David Albouy, Gabriel Ehrlich, and Minchul Shin, "Metropolitan Land Values," *Review of Economics and Statistics* 100(3) (July 2018): 454-466. Gary Schnitkey, "Cash Rent as a Percent of Farmland Price," farmdoc daily (6):211 (November 8, 2016).

[83] Tourte et al., 2015.

[84] AVCalc LLC, "Density: Spinach, Raw, and Links to Volume/weight Conversions," 2018, Accessed November 02, 2018.

[85] Milind Ladaniya, "13 - Transportation," In *Citrus Fruit: Biology, Technology and Evaluation*, 375-389, London: Academic, 2008, Accessed November 2, 2018.

[86] Assuming that transportation costs are shared in proportion to volume, the costs of shipping the spinach are the same whether it is shipped in whole or partial loads.

[87] Dan Murray and Alan Hooper, "An Analysis of the Operational Costs of Trucking: 2017 Update," American Transportation Research Institute, October 2017, Accessed November 2, 2018. N.B. This figure is a comprehensive estimate which includes fuel costs.

[88] Drew T Shindell, "The Social Cost of Atmospheric Release," Climatic Change 130, no. 2 (February 2015): 313-26, Accessed August 22, 2018, doi:10.1007/s10584-015-1343-0.

[89] To illustrate how these damages are impacted by an increasingly clean generation mix, we performed the same calculation using the proposed 2026 generation mix in Denver (24% coal and 23% natural gas). In this future generation mix scenario, the air pollution damages from the indoor farm's electricity drop to $29,000 per year.

[90] Mark Delucchi and Don McCubbin, "External Costs of Transport in the United States," A Handbook of Transport Economics (2010), Accessed November 2, 2018, doi:10.4337/9780857930873.00023, ("Delucchi and McCubbin, 2010")

[91] Delucchi and McCubbin, 2010.

Water Heating Case Study

Water heating has unique characteristics that make it a potentially attractive candidate for electrification. First, water heating accounts for a significant portion of household energy consumption (20 percent of the typical U.S. household).[92] Currently, roughly 48 percent of U.S. households have natural gas water heating, 46 percent have some form of electric water heating, and 6 percent use other fuels like fuel oil or propane. Conversion of gas or oil water heating to electric heating would have environmental benefits in a decarbonized power system, particularly when taking advantage of the high efficiency of heat pump technology.[93]

Second, electrification of water heating has the potential to introduce increased flexibility to the power system. Conventional electric resistance water heaters have participated in utility load control programs for decades. More recently, technological advancements have enabled "grid interactive water heating." Grid-interactive water heating allows the heating element of an electric resistance water heater to ramp up or down in response to real-time signals from the grid operator, providing valuable ancillary services or other load shifting benefits.[94]

At the same time, currently there are many conditions under which natural gas water heaters can more efficiently meet household water heating needs. Whether or not water heating electrification makes sense from an economic and environmental standpoint will depend on the market conditions in which the opportunity is being evaluated.

In this case study, we evaluate the costs and benefits of water heating technologies for a new single family home. We consider three water heating technologies: a natural gas water heater, a heat pump water heater, and a grid interactive electric resistance water heater.[95] For each technology, we estimate the net cost of meeting household water heating needs using the TVT. We evaluate the net costs under a range of market conditions to illustrate the relative advantages of each technology.

Market conditions vary across the scenarios according to the following factors: (1) the cost of electricity relative to natural gas, (2) the value of load flexibility, and (3) the marginal CO_2 emissions rate of electricity generation.

- *Electricity cost*: Marginal electricity costs have an average peak-to-off-peak price differential of $20/MWh and range from $30/MWh (peak) and $10/MWh (off-peak) at the lower end to $70/MWh (peak) and $50/MWh (off-peak) at the upper end.[96] In all cases, the natural gas price is held constant at $0.40 per therm.[97]
- *Value of load flexibility*: The value of load flexibility ranges from $20/kW-yr to $100/kW-yr consistent with observed frequency regulation prices.[98] The capacity of load flexibility for each water heater technology reflects the ability of the grid interactive water heater to provide real-time increases or decreases in load.
- *CO_2 emissions rate*: The CO_2 emissions rate of generation ranges from zero (e.g. wind or solar) to 1.2 tons/MWh (a typical coal plant). The range varies by peak and off-peak period across scenarios. As in the previous two case studies, we estimate the social cost of carbon according to the U.S. Government Interagency Working Group's 5% discount rate values, which escalates from $11 to $18 per metric ton of carbon dioxide between the years 2015 and 2035. The CO_2 emissions rate of the natural gas water heater is based on a constant assumption of the carbon content of natural gas of 0.0053 tons/therm.[99]

[92] Energy Information Administration, "Today in Energy: Space heating and water heating account for nearly two thirds of U.S. home energy use," November 7, 2018, Accessed February 19, 2019.

[93] David Farnsworth, Jim Lazar, and Jessica Shipley, "Beneficial Electrification of Water Heating," Regulatory Assistance Project, January 2019.

[94] A large smart water heating pilot was recently conducted by Bonneville Power Administration. See BPA, "CTA-2045 Water Heater Demonstration Report," BPA Technology Innovation Project 336, November 9, 2018. Also, see Ryan Hledik, Judy Chang, and Roger Lueken, "The Hidden Battery: Opportunities in Electric Water Heating," prepared for NRECA, NRDC, and PLMA, January 2016.

[95] Heat pump water heating load could potentially be controlled to reduce system costs. However, given the lower overall load and operational constraints of the technology, the incremental benefits of managing heat pump water heater load currently are low relative to the cost of the control technology and are not modeled in this case study.

[96] The 2018 average real-time peak and off-peak prices at the Duquesne transmission zone in PJM were $44.74/MWh and $30.40/MWh respectively, representing an average price differential of $14.35/MWh. See LCG Consulting, "PJM (PJM Interconnection) Real-time Price," 2018, Accessed February 19, 2019.

[97] Energy Information Administration, 1922-2017, "Natural Gas Prices," United States Department of Energy, January 31, 2019, Accessed February 15, 2019.

[98] Prior Brattle analysis found that a grid interactive water heater participating in the PJM RegD market in 2014 could have earned $180 in frequency regulation revenues in that year, or $80/kW-yr. See Ryan Hledik, Judy Chang, and Roger Lueken, "The Hidden Battery: Opportunities in Electric Water Heating," prepared for NRECA, NRDC, and PLMA, January 2016.

[99] Environmental Protection Agency, "Greenhouse Gases Equivalencies Calculator – Calculations and References," December 18, 2018, Accessed February 19, 2019. Consistent with the other case studies in this section, we have valued CO2 emissions at a rate of $15/ton.

The TVT is used to assess the net costs of each water heating technology, consistent with a system-level view rather than the cost to an individual consumer (which alternatively could be captured by the Participant Test). Costs include the upfront cost of the water heater, the cost of fuel (natural gas or electricity) used to heat water, the cost of supporting natural gas or electricity delivery infrastructure, and the cost of carbon emissions. Costs account for the time-specific profile of the water heating technology and assume that the grid interactive water heater is operated to minimize system costs (e.g., avoiding heating the water during peak hours). The flexibility value is treated as an offset to costs, and so subtracted from the total cost estimate.

Findings

When electricity costs are the highest – \$50/MWh (off-peak) to \$70/MWh (peak) – natural gas water heating is the most economic option. Figure 1 below shows that the flexibility value of grid interactive water heaters or the carbon emissions profile of the power supply mix are unable to offset the operating cost of the water heaters at higher electricity costs.

At low electricity costs of \$10/MWh (off-peak) to \$30/MWh (peak), electric water heating is the dominant option. Heat pump water heaters are most cost-effective when the value of load flexibility is low, and the grid-interactive water heaters become the most cost-effective option when the value of load flexibility rises to at least \$80/kW-yr. The two electric water heating technologies are similarly competitive when load flexibility value is in the middle of this range, with the higher efficiency heat pumps preferable for systems with higher emissions rates.

At moderate electricity costs of \$30/MWh (off-peak) to \$50/MWh (peak), the cost-effective technology is more sensitive to the flexibility value and emissions rates. Heat pump water heaters are more cost-effective than natural gas water heaters when the flexibility value is lower (\$60/kW-year or less) and electricity generation CO_2 emissions are low (0.4 tons/MWh or less). This is equivalent to the emissions rate of an efficient natural gas combined cycle unit, or a blend of a less efficient gas-fired unit and renewables. Grid interactive water heaters become the most economic option when CO_2 emissions rates are relatively low and the value of load flexibility is high (\$80/kW-yr to \$100/kW-yr).

Figure 1 summarizes the most cost-effective water heating technology under this range of market conditions, according to the TVT.

Natural gas water heaters have the most value in markets with a more carbon-intensive power supply mix, high electricity costs (relative to natural gas costs), and low flexibility value. Electric water heating will be the most competitive option in jurisdictions with a decarbonized power supply mix, but only if electricity costs do not rise significantly. If decarbonization is largely achieved through development of renewable generation, the increased flexibility needs of this system could place an emphasis on the value of grid interactive water heaters. Ultimately, additional considerations that are not captured in this case study, such as technical feasibility (e.g., physical space available for installation of the water heater), climate, and consumer preferences will likely lead to a mix of technologies in any given market.

Assumptions

Water heater installed costs: We have assumed an installed water heater cost (capital and installation) of \$1,300 for natural gas, \$1,800 for heat pump, and \$1,900 for grid interactive. Natural gas and heat pump cost assumptions are derived from a recent report by the Regulatory Assistance Project.[100] Grid interactive water heater costs are based on prior Brattle research and include the cost of communications and control technology as well as the incremental cost of a larger (i.e., 80-gallon) tank to accommodate greater thermal storage ability.[101]

Operating costs: Consistent with the TVT framework, electricity costs in this analysis are the wholesale cost of energy (i.e., fuel and O&M). The assumed electricity costs capture a wide range of possible average annual peak and off-peak prices, as described earlier in this section of the report. As a reference point, the median peak and off-peak prices at the MISO Indiana Hub were \$42/MWh and \$22/MWh, respectively, in 2018. We define the peak period as the period of daytime hours when water heating load could be avoided by a grid interactive water heater without sacrificing service to the

[100] David Farnsworth, Jim Lazar, and Jessica Shipley, "Beneficial Electrification of Water Heating," Regulatory Assistance Project, January 2019.
[101] Ryan Hledik, Judy Chang, and Roger Lueken, "The Hidden Battery: Opportunities in Electric Water Heating," prepared for NRECA, NRDC, and PLMA, January 2016.

Electricity Cost ($/kWh)		Electricity Cost ($/kWh)	Flexibility Value ($/kW-yr)	CO2 content of marginal electricity generation (tons/MWh)											
			Off-Peak	1.0	1.0	0.8	0.8	0.6	0.6	0.4	0.4	0.2	0.2	0.0	0.0
			Peak	1.2	1.0	1.2	0.8	1.0	0.6	0.8	0.4	0.6	0.2	0.4	0.0
Peak	Off-Peak														
0.07	0.05	High Cost Peak = $0.07 Off-Peak = $0.05	20	NG	NG	NG	NG	NG	NG	NG	NG	NG	NG	NG	NG
0.07	0.05		40	NG	NG	NG	NG	NG	NG	NG	NG	NG	NG	NG	NG
0.07	0.05		60	NG	NG	NG	NG	NG	NG	NG	NG	NG	NG	NG	NG
0.07	0.05		80	NG	NG	NG	NG	NG	NG	NG	NG	NG	NG	NG	NG
0.07	0.05		100	NG	NG	NG	NG	NG	NG	NG	NG	NG	NG	NG	NG
0.05	0.03	Moderate Cost Peak = $0.05 Off-Peak = $0.03	20	NG	NG	NG	NG	NG	NG	NG	HP	HP	HP	HP	HP
0.05	0.03		40	NG	NG	NG	NG	NG	NG	NG	HP	HP	HP	HP	HP
0.05	0.03		60	NG	NG	NG	NG	NG	NG	NG	HP	HP	HP	HP	HP
0.05	0.03		80	NG	NG	NG	NG	NG	NG	GI	GI	GI	GI	GI	GI
0.05	0.03		100	GI	GI	GI	GI	GI	GI	GI	GI	GI	GI	GI	GI
0.03	0.01	Low Cost Peak = $0.03 Off-Peak = $0.01	20	HP	HP	HP	HP	HP	HP	HP	HP	HP	HP	HP	HP
0.03	0.01		40	HP	HP	HP	HP	HP	HP	HP	HP	HP	HP	HP	HP
0.03	0.01		60	HP	HP	HP	HP	HP	HP	GI	HP	GI	GI	GI	GI
0.03	0.01		80	GI	GI	GI	GI	GI	GI	GI	GI	GI	GI	GI	GI
0.03	0.01		100	GI	GI	GI	GI	GI	GI	GI	GI	GI	GI	GI	GI

NG	= Natural Gas Water Heater
HP	= Heat Pump Water Heater
GI	= Grid Interactive Electric Resistance Water Heater

Figure 1. Most Cost-effective Water Heating Technology According to the Total Value Test (at Various Combinations of Electricity Costs, Flexibility Value, and Generation Emissions Rates)

customer, corresponding roughly to a period from 10 am through 10 pm. Natural gas prices are $0.25/therm and held constant across scenarios.[102]

We also account for non-fuel costs in the analysis, which largely consist of the cost of the infrastructure necessary to produce and deliver the fuel (natural gas or electricity). For natural gas water heating, non-fuel costs are $0.60/therm, based on the non-fuel portion of a typical residential natural gas electricity rate. For electric water heating, non-fuel costs are $0.07/kWh. We reduced these non-fuel costs for grid interactive water heaters to account for their ability to avoid capacity-related costs by shifting electricity consumption to off-peak hours when there is excess capacity. We assume that the net benefit of the modified load pattern accounts for avoided generation capacity cost of $60/kW-yr and marginal (i.e. avoidable) transmission and distribution capacity cost of $30/kW-yr.

Operating characteristics: We assume that a typical natural gas water heater uses 250 therms per year, based on a standard efficiency water heater. The grid interactive water heater uses 4,000 kWh per year, with all electricity consumption occurring during off-peak hours. While the range of electricity consumed by a heat pump water heater can vary significantly depending on the efficiency of the unit and the climate in which it is located, we assume that it would consume half the electricity of a grid interactive electric resistance water heater. We assume that the load profile of the heat pump water heater is split equally between peak and off-peak hours (i.e., 1,000 kWh of consumption annually in each period).

[102] Energy Information Administration, 1922-2017, "Natural Gas Prices," United States Department of Energy, January 31, 2019, Accessed February 15, 2019.

The maximum load of the grid interactive water heater's heating element is 4.5 kW and we assume its load flexibility capability is roughly half of its load (2.25 kW). During off-peak hours, the heating element could heat the water at an average level of 2.25 kW. When a load increase is needed to balance the system, the heating element could ramp up to 4.5 kWh. When a load decrease is needed, it could drop to zero. As long as the water heater is managed to heat the water at an average of 2.25 kW, it would meet the customer's hot water needs for the day.

Commentary on Case Studies

The purpose of these case studies is to illustrate the application of the TVT under a hypothetical set of conditions and associated assumptions. The three examples developed for this report were selected because they compare economically competitive electric and non-electric technology options under a reasonable set of conditions and constraints. They were selected independent of how other energy efficiency cost-effectiveness tests, each with its own unique stakeholder perspective, may evaluate them.

There are compelling examples of other efficient electrification technologies that have already been demonstrated to provide clear economic benefits to customers. For example, electric forklifts have been demonstrated in the field to provide a lower cost of ownership for customers compared to conventional forklifts with internal combustion engines, with an average payback of less than two years depending on local energy prices and usage levels. Electric forklifts feature fewer moving parts, so they are less costly to maintain. EPRI research indicates that an electric forklift is a more economical option for customers when usage exceeds 1,000 hours per year.[103]

In addition, electric lift trucks for materials handling have been shown to be economically favorable for customers compared to the traditional propane-powered alternatives. EPRI analysis indicates that electric lift trucks provide customers with a 37% cost savings compared to propane-powered lift trucks over a three year period, inclusive of capital and maintenance costs.[104]

Conclusion

This study undertook the assignment of identifying the most appropriate cost-effectiveness methodology and metric for all forms of energy efficiency, inclusive of efficient electrification. Based on a detailed review of the history and literature of energy efficiency cost-effectiveness analysis, coupled with insights from interviewed industry experts, the study examined how best to leverage the foundational elements of energy efficiency cost-effectiveness analysis in the California Standard Practice Manual (SPM) into a broader context.

The resultant test, which we have named the Total Value Test (TVT) has it roots firmly in the established cost-effectiveness tests of the SPM, with an emphasis on capturing the more comprehensive sets of benefits and costs associated with efficient electrification, while also being applicable to more traditional energy efficiency pursuits. The TVT strives to couple the Societal Cost Test's emphasis on valuing environmental externalities with the Total Resource Cost's approach to discounting future cost and benefit streams, while explicitly accounting for impacts on participating customers and society at-large.

The examples in *Case Studies* illustrate the application of the TVT in evaluating the cost-effectiveness of different types of efficient electrification activities. As evidenced by the water heating example, under different circumstances the TVT may find either the electric or non-electric technology the most favorable. The test is objective and not predisposed to favor any particular type of technology based on how it is powered or fueled.

While no cost-effectiveness metric is perfect, and there is room for constructive debate on the usefulness and challenges of the TVT, it does represent an effort to advance the discourse on cost-effectiveness in the context of new forms of energy efficiency such as efficient electrification.

This study is intended to inform all stakeholders involved in the design, approval, implementation, and evaluation of efficient electrification programs – and indeed any type of energy efficiency program – including utilities, regulators, third party program administrators, policy makers, and non-government agencies that influence public policy in the energy and environmental spheres.

EPRI intends to continue this area of study to further elucidate and illustrate the TVT with more case studies, and to engage stakeholders in outreach and dialogue towards advancing a new generation of energy efficiency and efficient electrification programs.

[103] "Electric Forklifts." Electric Power Research Institute. Palo Alto, CA. 3002014688. October 2018.

[104] "Rolling Along with Electric Lift Trucks." Electric Power Research Institute. Palo Alto, CA. 3002014681. November 2018.

Appendix: Assessing the Grid Flexibility Value of Electrification

This section elaborates on the grid flexibility impacts of electrification, including considerations for quantifying and monetizing this value.

Background

Multiple supply-, demand-, transmission- and distribution- side technologies and resources work in real-time coordination to meet energy demands and maintain the reliability of the electric system. Instantaneously balancing generation to meet electricity demand is a precise balancing act between both the supply-side and demand-side (and transmission-side when delivery constraints exist) to ensure that deviation is minimized.

The more the supply-side or demand-side varies across time, the more flexibility is required from the overall set of resources and technologies to maintain this delicate balance. Flexibility can be generally offered in the form of larger power output adjustable ranges, faster response rates, quicker start-up or shut-down times, longer sustainment times, and fewer constraints that limit the way a resource or technology can operate to meet the changing needs. More specifically, a large suite of reliability services across different time frames with different attributes are required to maintain system reliability, as shown in the figure below. The ability to provide these services and adjust how energy is provided fall under the category of power system flexibility.

Additional flexibility, just like additional energy supply, has associated costs, which vary among different flexibility resources and technologies. In restructured markets, such as those operated by Independent System Operators (ISOs) and Regional Transmission Organizations (RTOs), there are also different levels of monetary rewards for providing flexibility to the system, and corresponding incentives for incurring those costs of flexibility provision.

There are generally two metrics for quantifying the monetary value of a resource or technology providing flexibility.

1. The overall cost reduction that occurs when a resource provides flexibility at a lower cost than the existing resources. This is important to the system operator and the utility.
2. The revenue that a flexibility resource earns from providing flexibility in a market region. This is important for the owner, operator, or aggregator of the flexibility resource.

Both metrics can be used by organizations that conduct studies to evaluate the value of flexibility from a new resource, technology, market or set of resources, paradigm, or operating structure.

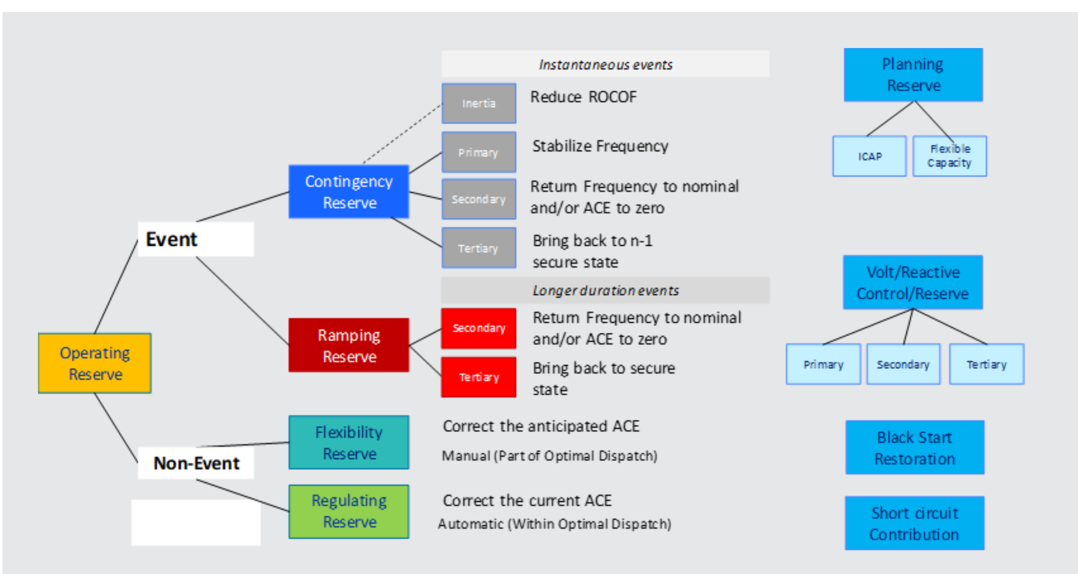


Figure 2. Grid Reliability Services

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Methods for Monetizing Value of Grid Flexibility

Approaches for determining the monetary value of a new technology or paradigm, such as efficient electrification, can vary depending on the time horizon considered. There is no single, uniform value of flexibility to the system, i.e., flexibility is not worth a specific $/kW value at all times nor for all regions. The value depends on the region, the time of day, day of week, season, future time horizon, and the specific flexibility attribute or reliability service. The transmission network, technologies already on the system, policies and reliability standards, electricity market design and structure, and fuel costs can all have impacts on the value as it changes temporally and spatially. To add to this complexity, the variation of values from different regions and time frames is not small – the value of a flexibility attribute may be null, and then hundreds of dollars per kW just hours or even minutes later. This makes the quantification difficult; however, there are useful approximation means that are meaningful enough to support policy decisions.

In the context of efficient electrification, it is useful to frame three cases of grid flexibility:

1. Incremental electrification, near term

2. Larger scale electrification, near term

3. Electrification, long term

Incremental Electrification, Near Term

To quantify the grid flexibility value of adding incremental amounts of electrification to the existing system, existing data can be used without much need for advanced simulation. All organized power markets in the U.S. post and store electric energy prices for all historic time periods as well as the reliability services that have organized markets. These prices can be evaluated to better understand the value of different electrification categories and technologies. Quantifying flexibility value for technologies that shift energy across time periods (e.g. reduce demand during high energy cost periods and increase demand during low energy cost periods) can be assessed through multiplying the energy reduction by the peak prices, offset by incremental energy consumption during the low-priced periods. In this case, only market energy prices are needed with simple calculations. For electrification technologies that can provide ramping capability, the prices during the highest ramp periods may be reduced, and those values can be used to quantify the value of flexibility. For those technologies that provide reliability services, like regulation or operating reserve, the prices of those services can be used to calculate value based on the time periods that the electrification technology is able to provide service.

Larger Scale Electrification, Near Term

The previous method works well for incremental electrification, because it can be assumed that it will not impact the price. When studying the value of large amounts of flexibility on the system, using the existing prices that an ISO posts may be less accurate, because larger scale electrification could potentially alter prices. In this case, it may be more accurate to gather data from the existing system and run production cost modeling simulations with the electrification resource added. The simulation will produce new prices for all services, which can then be used to better assess the value of added electrification in a similar manner to the previous incremental case. A simulation tool allows one to quantify the flexibility value of the reduced costs in addition to the flexibility value of revenue earned from flexibility provision.

Electrification, Long Term

Quantifying the grid flexibility value of electrification on a future system using existing system prices is typically not a feasible option. The ways in which prices of energy and ancillary services are set depend on many factors, such that simple scaling or trending assumptions for future prices from today's prices are not useful. Again, a power system simulation is generally required with the additional electrification technology added as part of the simulation. However, many other variables may need adjustment in the simulation to reflect the potential scenarios of the future system, such as future fuel prices, future resource mix, or other changes to factors that influence value. In this case, it is often useful to run multiple simulations to include different potential future scenarios. The resulting range of flexibility values can then be applied.

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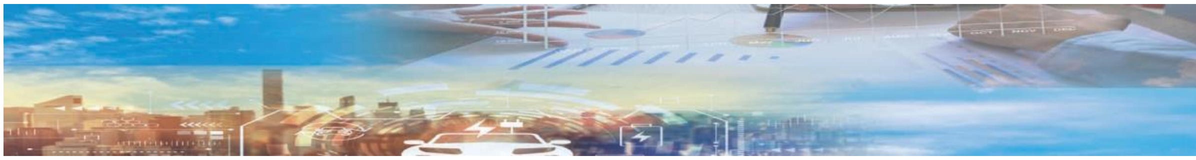

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Technology Innovation

The Electric Power Research Institute, Inc. (EPRI, www.epri.com) conducts research and development relating to the generation, delivery and use of electricity for the benefit of the public. An independent, nonprofit organization, EPRI brings together its scientists and engineers as well as experts from academia and industry to help address challenges in electricity, including reliability, efficiency, affordability, health, safety and the environment. EPRI also provides technology, policy and economic analyses to drive long-range research and development planning, and supports research in emerging technologies. EPRI members represent 90% of the electricity generated and delivered in the United States with international participation extending to 40 countries. EPRI's principal offices and laboratories are located in Palo Alto, Calif.; Charlotte, N.C.; Knoxville, Tenn.; Dallas, Texas; Lenox, Mass.; and Washington, D.C.

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Interoperability of Public Electric Vehicle Charging Infrastructure

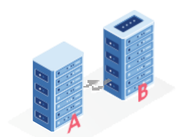
INTRODUCTION

This paper is a cooperative effort of the Electric Power Research Institute (EPRI), the Edison Electric Institute (EEI), the Alliance for Transportation Electrification (ATE), the American Public Power Association (APPA), and the National Rural Electric Cooperative Association (NRECA) to identify challenges, create awareness, and provide perspective to achieve greater interoperability and open standards in the burgeoning U.S. electric vehicle (EV) charging market.

*By definition, **interoperability** is the ability for multiple systems to work together without restriction. With regards to electric vehicle charging infrastructure, interoperability refers to the compatibility of key system components—vehicles, charging stations, charging networks, and the grid—and the software systems that support them, allowing all components to work seamlessly and effectively.*

Research and stakeholder engagement over the last decade have shown that interoperable, transparent, open standards-based public EV charging infrastructure can improve the overall customer experience, promote efficient capital investment, enable more optimal EV-grid integration, and support adoption of EVs.

This paper distills, at a high level, four key challenge areas related to interoperability:



CHARGING NETWORK-TO-CHARGING NETWORK

CHARGING STATION-TO-NETWORK

PHYSICAL CHARGING INTERFACE

VEHICLE-GRID

And considers their implications for:

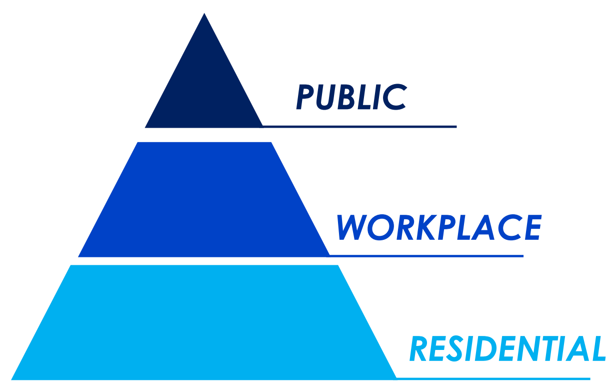
CUSTOMERS

SITE HOSTS

ELECTRIC COMPANIES

MOTIVATION

The electric vehicle market is rapidly accelerating, as is investment in the charging infrastructure needed to support this growing market. While the vast majority of EV charging now takes place at home and at work, widespread, open-access public charging infrastructure will be essential to support EV drivers beyond early adopters. Visible public infrastructure is a must for more customers to consider EVs as viable for meeting all of their driving needs—from daily commutes to major expeditions—while also supporting drivers who might not have access to workplace or home charging (such as apartment dwellers and other drivers without dedicated residential parking). As a general expectation, public EV charging infrastructure should be convenient and reliable for drivers to use. A recent EEI/Institute for Electric Innovation report[1] projects that, by 2030, nearly one million public charging ports will be needed in the U.S. to support nearly 19 million EVs. Today, fewer than 100,000 such ports are available to U.S. drivers,[2] and many of these impose limits on their access and use. As infrastructure scales to meet these needs, improved interoperability and standardization will be essential to help enable a multi-stakeholder approach to planning, investment, and operation of public charging.

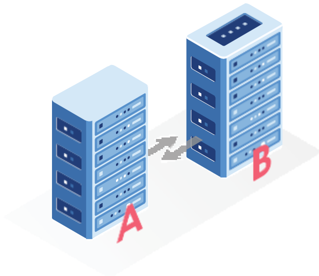


To date, public charging infrastructure in the U.S. has developed through a patchwork of grant funding, settlement funds, private investment, and electric company pilots and programs. The largest portion of public charging is managed by charging network providers, called electric vehicle service providers (EVSPs)–companies that operate charging stations under a variety of business models. Many rely on proprietary software and subscriber service models, resulting in different pricing structures and service offerings for their subscribers versus non-subscribers.

1. *Electric Vehicle Sales Forecast and the Charging Infrastructure Required Through 2030.* Institute for Electric Innovation (IEI) and Edison Electric Institute (EEI), Washington, DC: 2018.
2. *Plug-In Electric Vehicle Charging Infrastructure Strategy Update.* EPRI, Palo Alto, CA: 2018. 3002011592.

INTEROPERABILITY
WHERE TO FOCUS

The four key interoperability-related challenge areas are described below.

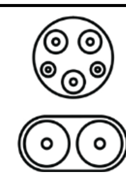
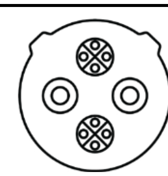


<u>Charging network-to-charging network:</u> EVSPs tend to operate their respective networks as islands, lacking communication or integration with other networks. In the current industry vernacular, interoperability most often refers to a vision in which EV drivers can access public charge points from any owner/operator through a common platform and a single network subscription or contract, often called "e-roaming." Several EVSP networks have signed bilateral agreements to implement roaming partnerships in the past year, marking vital progress towards increased access to networked public charging.

Behind the scenes, this customer-friendly, public charging infrastructure depends on a web of business-to-business (B2B) contracts between network providers, and interoperability among their respective back-end systems. Familiar analogies include the interoperability of financial and banking systems to enable inter-bank and cross-border automated teller machine (ATM) usage and mobile roaming capabilities enabled by interoperability among multiple wireless telecommunication networks.

<u>Charging station-to-network:</u> By definition, networked charging stations must communicate with their supporting networks. Proprietary protocols can create "vendor lock-in" challenges that commit customers (typically the charging station owner) to a single, closed-network provider for the lifetime of the charging equipment. An open standards-based approach that includes both technical capabilities and contractual rights allows owner-operators to switch between network service providers without having to purchase new charging stations and to install new charging stations without having to change network service providers. This can help stimulate competition in the marketplace and protect infrastructure investments against obsolescence. The Open Charge Point Protocol (OCPP)* is an open networking standard that is widely used in Europe and is growing in acceptance in the U.S. While current versions (OCPP 1.5, 1.6, and 2.0) exhibit some gaps in functionality, their acceptance by most network providers and continued development are important to addressing network interoperability.

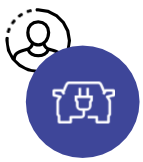
<u>Physical charging interface:</u> While a single standard for common AC charging is widely accepted in the U.S. (with Tesla vehicles requiring an adaptor), three different DC charge ports[3] are used today. Issues with fragmentation of the early Level 2 AC charging market were mitigated by adoption of the SAE J-1772 standard, which provides automakers and those deploying charging infrastructure with a common system architecture. Meanwhile, the lack of a single accepted standard for DC charging for light duty EVs increases operational complexity and costs, and can lead to customer confusion as public DC fast charging expands.

DC Standard	Connector	Used By
SAE Combined Charging System (CCS)		GM, Ford, Honda, KIA, Hyundai, BMW, Mercedes, Porsche, Audi, VW
CHAdeMO		Nissan, Mitsubishi
Tesla Supercharger		Tesla

3. *Direct Current Fast Charger System Characterization: Standards, Penetration Potential, Testing, and Performance Evaluation.* EPRI, Palo Alto, CA: 2011. 1021743.

* *Use of OCPP does not guarantee charging station-to-network interoperability.*

Vehicle-grid: Collaboration among EV and charging station manufacturers, network operators, site hosts, and electric companies will be necessary to implement emerging vehicle-grid integration (VGI) technologies.[4] Vehicle-to-grid charging benefits both the electricity grid and the vehicle owner. At present, electric companies and grid operators are limited in their engagement to support secure, cost-effective, reliable public charging stations at scale by the lack of interoperability among networked systems and limited implementation of open protocols for electric company communications.



CUSTOMER IMPACT

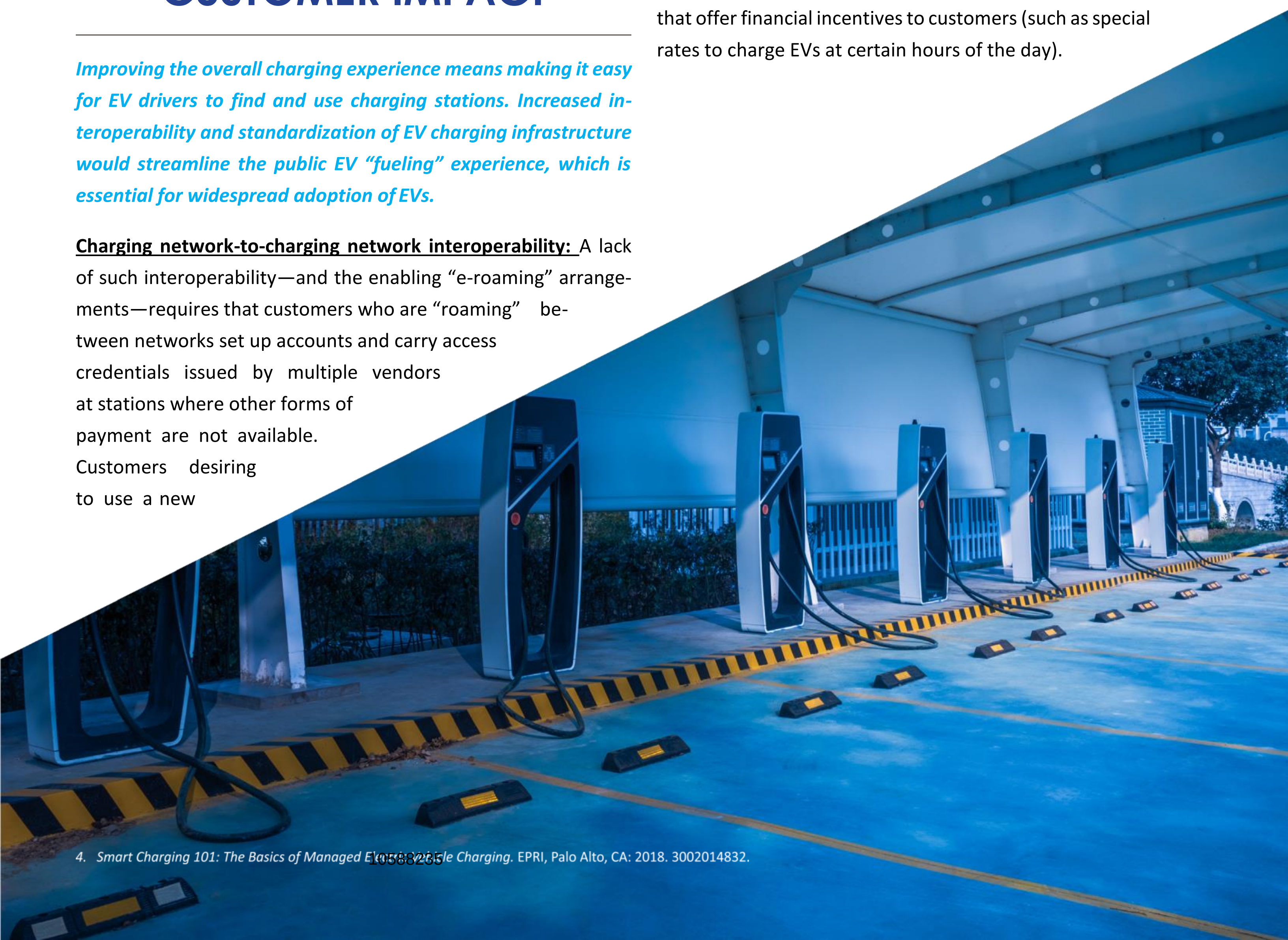
Improving the overall charging experience means making it easy for EV drivers to find and use charging stations. Increased interoperability and standardization of EV charging infrastructure would streamline the public EV "fueling" experience, which is essential for widespread adoption of EVs.

Charging network-to-charging network interoperability: A lack of such interoperability—and the enabling "e-roaming" arrangements—requires that customers who are "roaming" between networks set up accounts and carry access credentials issued by multiple vendors at stations where other forms of payment are not available. Customers desiring to use a new network must complete a lengthy signup process or use a toll-free phone line to initiate a charge session. "Islanded" charging networks limit the ability to provide customers with charging station maps that include real-time station status data from multiple networks, which is already a concern where EVs are widespread, as drivers must often wait in queue for public charging.

Charge station-to-network interoperability: Open standards-based communications protocols offer service providers and site hosts flexibility in equipment selection that could foster competition and encourage industry innovation by enabling adoption of new technologies, to the benefit of customers.

Physical charging interface interoperability: The existence of multiple interface designs for DC fast charging may add to customer confusion if the charging plaza does not have all the connectors at its stations and limits the portion of installed charging available to any given driver.

Vehicle-grid interoperability: Increased end-to-end interoperability of EV charging infrastructure could streamline communications needed to implement electric company smart charging programs that offer financial incentives to customers (such as special rates to charge EVs at certain hours of the day).



4. *Smart Charging 101: The Basics of Managed Electric Vehicle Charging.* EPRI, Palo Alto, CA: 2018. 3002014832.

Unlike gas stations, the vast majority of EV charging occurs at home, work, or public locations that the driver frequents—the "fueling" location is infrequently a destination in itself. Electric vehicle charging is an entirely different "refueling" paradigm with a range of cost and convenience advantages, but it is still imperative to ensure that the public charging experience meets or exceeds customers' expectations set by the baseline "gas station model."

To highlight customer challenges posed by non-interoperable public charging infrastructure, the table below compares the ***public "fueling" experiences of electric vehicle drivers to those of conventional vehicle drivers:***

	Conventional Vehicle Fueling Experience	Public Electric Vehicle Fueling Experience	Ongoing Efforts to Improve Public Charging Experience
Access	Fill up at any gas station; no membership or prior contract required.	Must maintain accounts and access credentials with all networks they wish to utilize.	Many EVSPs are working towards e-roaming.
Payment	Standard forms of payment (credit/debit, cash) accepted at any gas station.	Most public charge points do not accept credit/debit cards; EV drivers must juggle multiple network-specific access cards, apps, and associated accounts to pay for public charging sessions.	Concepts that allow for automatic charging session initiation and payment are being introduced by automotive companies and charging networks.
Pricing	Fuel prices are market-driven and consistently displayed on a $/gallon basis; drivers can easily compare options.	Many pricing schemes are complex and lack consistency and transparency; may be displayed as $/kWh, $/unit time, or $/session.	Complexity in pricing remains an open issue due to regulation, business models, and bundling with parking/other services or even the purchase of an EV.
Reliability and availability	Navigate to virtually any gas station with the expectation to refuel immediately.	Difficult to find accurate station status, with public charge points often unavailable because they are either in use, out of order, or access is blocked by a non-charging vehicle.	-Each network has its own app with station locations, and this information is also often available through third party apps. -Google Maps recently added charging station locations, and real-time availability info is available for certain networks. -The charging industry is also working on allowing EV drivers to make reservations for public charging.
Vehicle compatibility	Universal expectation that the fuel nozzles at every gas station will fit.	For DC fast charging, drivers must locate chargers compatible with their vehicles; connection types differ by automaker and region.	For non-Tesla DC fast charging stations, site hosts often install both CCS and CHAdeMO connectors.

SITE HOST IMPACT

Chargers are widely available for purchase by commercial landlords as well as network operators. While network operators generally possess the knowledge and experience to make informed decisions about chargers and associated software, commercial and multifamily landlords typically are unaware of the limitations presented by hardware that is restricted from moving between networks. In cases where the charger owner wants to change network providers, for pricing, service, or other reasons, the lack of interoperability typically presents obstacles that often are costly and burdensome.

Charging network-to-charging network interoperability: Network interoperability enables customers to use stations across networks. This can broaden the customer base with access to a particular site host's charging equipment. It also allows for site inclusion in public charging mapping programs, including those providing real-time status, thus improving equipment utilization.

Charge station-to-network interoperability: Many commercial charging equipment providers bundle their charging hardware with software so that the hardware is incompatible with other networks. When the lack of open standards is compounded by contractual restrictions for charging station control systems, a host desiring to change network service providers will likely need to purchase and install entirely new charging hardware. By installing a networked charging station, site hosts are often tied to the original network provider for the hardware's lifetime, limiting customer mobility and competition.

Information barriers resulting from networked chargers' proprietary communications protocols present challenges to the site hosts, hardware owners, and other stakeholders responsible for their long-term operation and maintenance. Open standards-based approaches would mitigate these integration challenges, while improving site hosts' ability to monitor the condition of their charging stations in real time to ensure timely maintenance.

Physical charging interface interoperability: Site hosts are forced to decide which of the three prevalent DC fast charging standards they will support. Supporting multiple formats adds equipment complexity and cost and may increase the footprint required to serve a given number of vehicles.

Vehicle-grid interoperability: The inability to manage the vehicle-grid interaction may hamper the site host's ability to manage on-site charging in ways that reduce electricity costs for the site host.

ELECTRIC COMPANY IMPACT

Some electric companies install, own, maintain, and operate public EV charging infrastructure as utility owner-operators, while others focus on providing the conduit, wiring, and other necessary on-site infrastructure. To meet customer needs, electric companies are engaged in various ways with EVSPs, site hosts, and others in the early stages of charging infrastructure development. Electric companies serving as the owner-operator may select one network as the turnkey operator after issuing an RFP. Others electric companies may engage multiple vendors and operating systems to operate in their service territories – integrating their IT and management systems with the vendors' systems and associated data (which is generated, controlled, and managed by the EVSPs).

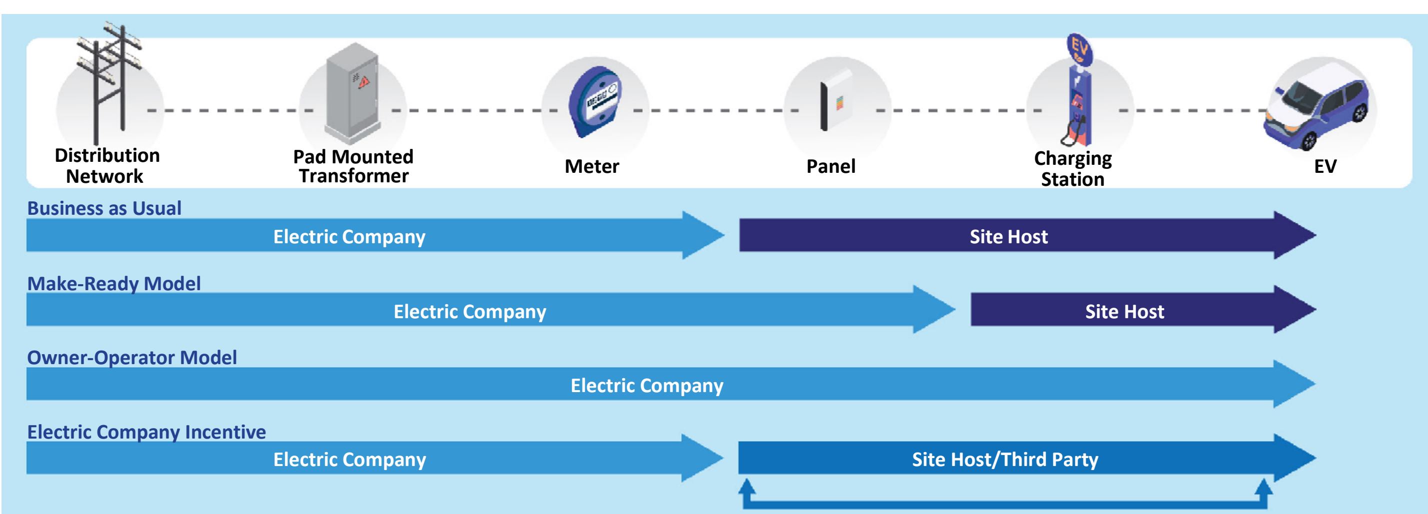
Charging network-to-charging network interoperability: Enabling customers to use stations across networks broadens the customer base for installed equipment, increasing utilization of the charging infrastructure.

Charge station-to-network interoperability: Like site hosts, some electric companies install, own, and operate public EV charging infrastructure through third-party networks, meaning resulting charging points are not open-access. To access these (often rate-based) public infrastructure investments, customers must first subscribe to a proprietary network as a member.

Due to proprietary back-end software and the charge station hardware locked to it, the electric company owner-operators of networked public charging risk stranding assets, potentially rendering these investments unusable if the selected network provider curtails or ceases operations.

When charging assets are deployed with bundled hardware and proprietary software, utility owner-operators may be tied to the same lifetime vendor commitment (and associated challenges) faced by site hosts, but on a much larger scale. They may face restrictions in negotiating the most cost-effective solution for customers.

Physical charging interface interoperability: Depending on local and site-specific infrastructure, new DC fast charging installations may require distribution upgrades. As the fast charging market expands and as vehicles capable of higher-powered charging en-



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ter the market, the frequency and extent of required upgrades to the grid will likely increase. The existence of multiple disparate, non-interoperable DC fast charging standards could limit the efficiency of these charging infrastructure investments.

Vehicle-grid interoperability: The lack of networked charging system transparency and interoperability inhibits the ability of electric companies to manage public charging infrastructure securely, cost-effectively, and reliably, while also planning for future public charging growth. For electric company owner-operators, this creates inefficiencies in the operation and maintenance of public charging. Secure, integrated communication between the grid and downstream components of EV charging infrastructure is required for optimal EV-grid integration, but is impeded by a lack of open standards, interoperability, and transparency in the current model.

CONCLUSION

Without broadly addressing interoperability issues, U.S. public charging infrastructure will continue to scale along fragmented and inefficient paths, potentially resulting in higher costs, less than optimum customer experience, and stranded investments. Sustainable, effective infrastructure development requires a shared focus on interoperability, transparency, and open-standards to streamline system integration and improve the customer experience. From the customer's perspective, the goal should be more than a system that "just works" – and one that offers convenience, confidence, and security.

COLLABORATIVE AREAS OF FOCUS

Charging network-to-charging network interoperability: Implementation of a standard protocol for B2B connectivity that facilitates customer roaming between charging networks.

Charge station-to-network interoperability: Implementation of open, nonproprietary protocols enabling interchangeable services and operations between charge stations and networks.

Physical charging interface interoperability: The adoption, through appropriate standards-setting organizations, of a DC charging protocol and interface, or alternative solutions to facilitate interoperability, for light duty EVs to improve charging access and scale infrastructure efficiently.

Vehicle-grid interoperability: Development and implementation of open standards for grid-condition based charging management.

By working together, all stakeholders in public EV infrastructure—including EVSPs, electric companies, EV supply equipment OEMs, and automakers—can help advance both technical and best practice solutions to interoperability-related challenges. This includes collaborative efforts to inform and support standards development and implementation through industry forums such as The National Electric Transportation Infrastructure Working Council (IWC).

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GLOSSARY OF TERMS

AC, DC: alternating current, direct current. The U.S. electricity grid operates on AC. A typical household outlet is 110–120 VAC (volts alternating current). Large home appliances use 240 VAC. Electric car batteries operate on DC.

Charging Level: The terms, AC Level 1, AC Level 2, and DC Fast describe how energy is transferred from the electrical supply to the car's battery. Level 1 is the slowest charging speed. DC Fast is the fastest. Charging rate varies within each charging level, depending on a variety of factors including the electrical supply and the car's capability.

CHAdeMO: An abbreviation of "CHArge de MOve", A DC fast charging standard co-developed by Tokyo Electric Power Company (TEPCO) and Japanese automakers.

CCS: Stands for "Combined Charging System." A charging standard developed by the Society of Automotive Engineers (SAE) and the European Automobile Manufacturers Association that supports both AC and DC charging, combined in a single plug design.

Connector: The plug that connects the electricity supply to charge the car's battery. J-1772 is the standard connector used for Level 1 and Level 2 charging. CCS or "Combo" connectors are used for DC Fast charging on most American and European cars. CHAdeMO is the connector used to DC Fast charge some Japanese model cars.

EVSE: Electric vehicle supply equipment. An industry term for the charging appliance. Most people say chargers or charging stations. Charging station once referred to just the appliance but now is also being used to describe a location with multiple chargers (think: gas station).

EVSP: Electric vehicle service providers. Companies that deploy and operate charging station networks.

3002017164 August 2019

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BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

Dan Lipschultz	Commissioner
Matthew Schuerger	Commissioner
Katie J. Sieben	Commissioner
John A. Tuma	Commissioner

In the Matter of a Commission Inquiry into Electric Vehicle Charging and Infrastructure

ISSUE DATE: February 1, 2019

DOCKET NO. E-999/CI-17-879

ORDER MAKING FINDINGS AND REQUIRING FILINGS

INTRODUCTION

While still a small share of the market, electric vehicle (EV)[1] sales are growing rapidly and show signs of increasing growth. The Legislature has taken steps to facilitate the adoption of EVs in Minnesota. Minn. Stat. § 216B.1614 requires each public utility to have a tariff specifically designed for EV charging that offers time-of-day or off-peak rates to customers who own EVs. Minn. Stat. § 216B.02, subd. 4, exempts entities that sell electricity for EV charging from regulation as a public utility, which allows non-utilities to develop and operate charging infrastructure.

EVs have the potential to benefit Minnesota in numerous ways, but could also adversely impact the electric system if their integration is not planned. In order to facilitate EV integration in a manner consistent with the interests of the public and of ratepayers, the Commission initiated this investigation into EV charging and infrastructure.

PROCEDURAL HISTORY

On December 28, 2017, the Commission opened the present docket by issuing a Notice. The Notice stated,

> The purpose of this inquiry is to gather information and gain a better understanding of the following:
>
> 1. The possible impacts of EVs on the electric system, utilities, and utility customers, including the potential electric system benefits;

[1] Minn. Stat. § 169.011, subd. 26a, defines "electric vehicle" as "a motor vehicle that is able to be powered by an electric motor drawing current from rechargeable storage batteries, fuel cells, or other portable sources of electrical current, and meets or exceeds applicable regulations in Code of Federal Regulations, title 49, part 571, and successor requirements." The definition includes a neighborhood electric vehicle, a medium-speed electric vehicle, and a plug-in hybrid electric vehicle.

2. The degree to which utilities and utility regulatory policy can impact the extent and pace of EV penetration in Minnesota; and

3. Possible EV tariff options to facilitate wider availability of EV charging infrastructure.

The public interest should benefit from a better understanding of these issues and from more regulatory certainty.

On March 16, 2018, the Commission convened a public workshop featuring national and local EV experts in order to discuss the challenges and opportunities surrounding EV adoption in Minnesota.[2] The workshop included panels on charging infrastructure, cooperative and municipal utility EV initiatives, and investor-owned utility and stakeholder perspectives.

On May 9, 2018, the Commission issued a Notice of Comment Period, requesting comment on a variety of EV issues including barriers to EV adoption, guiding principles for EV adoption, the possible effects of increased electric retail sales for EVs, cost recovery for EV-related investments, EV pilot programs, and cost-benefit analysis of EVs.

By August 8, 2018, the following parties submitted comments in response to the May 9 Notice:

- Alliance for Transportation Electrification
- Center for Energy and the Environment
- Ceres
- ChargePoint, Inc.
- Citizen's Utility Board of Minnesota
- Dakota Electric Association
- Fresh Energy, Natural Resources Defense Council, Sierra Club, & Minnesota Center for Environmental Advocacy (the Clean Energy Organizations, or CEO)
- Greenlots
- Institute for Local Self-Reliance
- Minnesota Department of Commerce, Division of Energy Resources (Department)
- Minnesota Pollution Control Agency & Minnesota Department of Transportation (MPCA/MDOT)
- Minnesota Power
- Office of the Minnesota Attorney General, Residential Utilities and Antitrust Division (OAG)
- Otter Tail Power Company (Otter Tail Power)
- Siemens
- Tesla, Inc.
- Union of Concerned Scientists
- Xcel Energy

[2] The Commission issued notices of the workshop on February 1, 2018 and March 5, 2018.

By August 24, 2018, the following parties filed reply comments:

- Center for Energy and the Environment
- CEO
- ChargePoint, Inc.
- Citizen's Utility Board of Minnesota
- The Department
- Greenlots
- MPCA
- Siemens
- Tesla, Inc.
- Union of Concerned Scientists
- Xcel Energy

On December 13, 2018, the Commission met to consider the matter.

FINDINGS AND CONCLUSIONS

I. Summary of Commission Action

In this order, the Commission will make general and specific findings regarding EVs in Minnesota based on the input received in the course of this investigation, and will direct Xcel Energy, Minnesota Power, and Otter Tail Power to submit plans and proposals for EV-related programs and investments.

The Commission received comments and reply comments from many different stakeholders, each with a unique perspective and expertise regarding EVs and the broader electric system. The Commission has reviewed and considered these comments, and this order discusses below the most prominent issues that emerged from these comments.

II. Key Issues

Issues discussed in this section are not necessarily the views of the Commission, but rather a summary of the issues raised in the course of the investigation. The Commission offers this summary to provide context for the Commission's findings and order, which are informed by these views.

A. Potential Benefits of and Barriers to EVs

1. Benefits of EVs

EVs have the potential to deliver a variety of benefits to Minnesota, especially environmental and public health benefits. Replacing fossil fuel powered vehicles with EVs can reduce greenhouse gas and other harmful emissions, especially as the rise of EVs coincides with the rise of renewable energy and the decline in coal-fired electric generation.

Reducing greenhouse gas emissions is key to stopping climate change, and Minnesota has accordingly established greenhouse gas emissions reduction goals.[3] But according to MPCA, the transportation sector is a leading source of greenhouse gas emissions in Minnesota and has not significantly reduced emissions levels.[4] Increasing the adoption of EVs in Minnesota can help the state meet its emissions reduction goals and fight climate change.

Fossil-fuel powered vehicles also emit harmful pollutants that can cause adverse public health effects.[5] These harmful pollutants tend to disparately impact minority and low-income areas where emissions are higher. Switching to EVs can help reduce emissions of these harmful pollutants and improve health outcomes in these vulnerable communities.

By using more electricity, EVs can benefit all ratepayers. An increase in electricity sales can drive down rates for all ratepayers "by spreading the utilities' fixed costs over a greater amount of kilowatt-hour sales,"[6] especially if EV charging occurs during times of low demand when not as much electricity is consumed by customers. It is estimated that an EV driver uses 4,000–5,000 kilowatt hours annually, but the Department concluded that significant growth in EVs is necessary before it would noticeably impact electric consumption.[7]

Utilities can play a role in advancing these wide-ranging potential benefits by helping facilitate the growth of EVs through education of the public and development of EV charging infrastructure.

2. Barriers to EVs

Widespread EV adoption is not a given due to conditions that can hamper the growth of EVs. The two main barriers to EVs that have been identified in this docket are insufficient charging infrastructure and lack of consumer awareness of EVs and their benefits.

These barriers are intertwined, because a great way to remind consumers about EVs and show that EVs are a viable and convenient option is for consumers to encounter charging infrastructure as they go about their day. Potential EV owners have reported concerns about being able to complete their driving trips on a single charge, a phenomenon that has been labeled "range anxiety." Installing plenty of chargers that potential EV owners encounter regularly can help counteract range anxiety and encourage EV adoption. Developing charging infrastructure is therefore a potential prerequisite to significant growth in EVs. However, third-party charging providers can face difficulties in developing charging infrastructure without robust EV ownership to support it. Utilities can play a role in facilitating and developing charging infrastructure in order to help bridge this gap.

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[3] Minn. Stat. § 216H.02.

[4] MPCA/MDOT comments at 1.

[5] *See, e.g., In the Matter of the Further Investigation into Environmental and Socioeconomic Costs Under Minnesota Statutes Section 216B.2422, Subdivision 3,* Docket No. E-999/CI-14-643, Order Updating Environmental Cost Values at 32–33 (January 3, 2018) (Updating Environmental Costs Order).

[6] CEO comments at 5.

[7] Department comments at 5.

B. Important Components of EV Proposals

1. Designing Efficient and Effective Rates

The electric system is designed to provide safe and reliable service at all times, including times of peak demand, which is the time of day when electricity use by the public is at its highest. In Minnesota, peak demand generally occurs during the evening hours when most people have returned from work, with the lowest demand occurring overnight.[8] The growth of EVs has the potential to significantly impact the electric grid, because scores of EVs charging during times of peak demand could necessitate large investments in generation and distribution infrastructure to handle this new load. Fortunately, rate design can be an efficient and effective tool for avoiding these costly investments.

Time-of-use rates adjust the price of electricity based on the time that it is consumed, with low prices during low-demand periods and high prices during peak demand. A time-of-use rate could therefore encourage charging during times of low demand and impose higher rates for usage when demand is high to reflect the additional costs this usage imposes on the system. Using rate design to encourage charging during times of low demand can help the electric grid absorb and accommodate the new load created by EVs without the need for new generation or distribution infrastructure, thereby enhancing the efficient use of existing infrastructure and potentially driving down electricity rates.

Rate design mechanisms intended to encourage off-peak charging through lower rates at those times can be particularly effective for persuading public and private fleet managers to switch to EVs. Fleet managers "tend to be very sensitive to operations and maintenance costs, and so are more accustomed to thinking in terms of total cost of ownership" and therefore more likely to consider fuel cost savings in choices about vehicle types.[9]

Another benefit of encouraging charging during times of low demand is that overnight electricity consumption also tends to correlate with high generation of Minnesota's most abundant renewable resource: wind power. Matching EV charging with wind generation could allow utilities to make better use of the wind resource and potentially support increased wind generation, which can help Minnesota meet its greenhouse gas and harmful emission reduction goals.

Smart or managed charging takes rate design a step further by enabling the utility to actively manage the charging load. Chargers can be equipped with two-way communication capabilities between the utility and the EV, which allows the utility to remotely control the rate of EV charging in order to meet a local or regional system need. For example, the utility could ramp up EV charging during times of high wind generation, and the utility could curtail charging during peak demand in areas with high EV penetration to defer the need for distribution infrastructure upgrades.

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[8] Department comments at 7.

[9] CEO comments at 21.

2. Educating Ratepayers about EV Options and Benefits

The EV tariff statute allows utilities to recover costs incurred “to inform and educate customers about the financial, energy conservation, and environmental benefits of electric vehicles and to publicly advertise and promote participation in the customer-optional tariff.”[10] A plain reading of this provision authorizes cost recovery for education efforts by a utility that go beyond simply encouraging customers to enroll in the utility’s EV tariff. The statute contemplates that utilities could disseminate information to customers about the overall benefits of EVs, such as the financial benefits to the individual customer in the form of lower fuel costs and broader environmental benefits of widespread EV adoption.

Utilities are uniquely situated to educate the public about the benefits of EVs because of their existing relationships and frequent contact with their customers. Education efforts could even target public and private fleet managers to encourage the transition of vehicle fleets to EVs—a high-impact opportunity for boosting EV adoption. Since lack of awareness about the benefits of EVs is a major barrier to EV adoption, utility efforts to educate ratepayers about benefits of EVs can be an efficient and effective way to encourage EV growth.

3. Investing in EV Charging Infrastructure

Because EV charging infrastructure must connect to the electric grid, utilities inevitably play a role in the development of that infrastructure. At a minimum, the utility will treat a customer hosting charging infrastructure like any new customer by providing a service connection to the customer, including any necessary distribution upgrades, up to and including the meter. The costs of the service connection are then allocated to the customer hosting the charging infrastructure in the same manner as any new customer.

Utilities can take on a larger role in developing EV charging infrastructure by assuming more of the costs and spreading them across all ratepayers. Under the “make-ready” approach, the utility could cover the cost of connecting the charging infrastructure up to the point where the charger connects to the grid. This approach could reduce the cost of building charging infrastructure, which could increase the economic viability of that infrastructure.

Utilities could build and own EV chargers, which would ensure development of charging infrastructure and strongly support the growth of EVs. A less direct approach could involve the utility offering financial incentives to third-party charging providers to build charging infrastructure.

Another factor to consider regarding EV charging infrastructure is the type of infrastructure that will be installed. For example, direct current fast charging (DCFC) infrastructure allows users to recharge in 10–30 minutes, drastically reducing charging time compared with traditional EV chargers and enhancing the potential for combined charging and parking services.

With any approach to development of EV charging infrastructure, there will be questions about which costs should be recovered from ratepayers and why. There are a number of mechanisms for cost recovery, as explained further below.

[10] Minn. Stat. § 216B.1614, subd. 2(c)(2).

4. Cost Recovery of EV-Related Investments

Any discussion of utility investments raises the issue of how the utility will recover the cost of those investments from ratepayers. Utilities recover costs from ratepayers through a variety of mechanisms, depending on the type of cost being recovered. Different types of cost recovery can incentivize certain investments and behaviors of the utility.

In the course of this investigation, stakeholders suggested a variety of approaches to cost recovery for EV-related costs. A utility's capital investments in EV infrastructure could be added to rate base through a rate case and earn a rate of return on the investment. The Commission has also authorized cost recovery outside of a rate case through riders. Utilities could be allowed to earn a higher rate of return on EV-related investments as an incentive. Attaching performance metrics to EV-related costs could tie cost recovery to the utility's achievement of certain goals, such as customer participation or satisfaction. Allowing the utility to recover EV-related costs as operating expenses would distribute cost recovery across all ratepayers but without the utility earning a rate of return on those costs. To be clear, the Commission generally decides recovery of a utility's cost of service on a case-by-case basis considering factors such as the purpose, nature, magnitude, and potential benefits of the costs incurred.

For investments serving only one customer, such as home charging equipment, it may be appropriate to recover the cost from that customer. These costs could be recovered over time using on-bill financing, which would recover a portion of the cost through the customer's electric bill each month, thereby easing the burden of the cost to that customer.

5. Promoting Connections Through Interoperability

One concern with the buildout of EV charging infrastructure is "interoperability," which broadly refers to the integration between different charging networks, as well as integration between charging infrastructure and different models of EVs. Interoperability is viewed as an important principle in the development of EV charging infrastructure to ensure a smooth user experience for customers and enable different types of chargers to communicate across networks. The Commission has no authority over third-party charging providers and how they choose to build charging infrastructure in Minnesota, but the Commission can encourage and mandate interoperability in utility proposals for development of charging infrastructure.

One aspect of interoperability is the Open Charge Point Protocol (OCPP), an informal standard that enables communication between a charging station and network management system. Another aspect of interoperability is Open Automated Demand Response (OADR), which enables the two-way communication between the EV and the utility that is necessary for smart charging.

C. Commission Consideration of EV Proposals

1. Weighing Effects Through Cost-Benefit Analysis

The Commission generally evaluates a proposal on its own terms based on the record developed in that docket. This approach promotes consideration of the unique context surrounding the proposal. In addition, the Commission frequently weighs the costs and benefits of a particular proposal in order to determine whether the proposal is in the public interest. Parties can submit a formal cost-benefit analysis that attempts to quantify various costs and benefits to determine whether the benefits outweigh the costs, or vice versa.

Determining the appropriate level of cost-benefit analysis to inform the Commission's decision can depend on the magnitude of the proposal. For example, a large, expensive project may require a more detailed cost-benefit analysis to persuade the Commission that approval is in the public interest, while a smaller pilot project that is intended to experiment with a new idea in a low-risk manner may not require such extensive analysis.

One challenging aspect of conducting a cost-benefit analysis can be in attempting to quantify the costs and benefits that could result from implementing the proposal. Fortunately, the Commission recently conducted an extensive investigation into the societal costs of fossil fuel emissions and established dollar values attributable to carbon emissions and other harmful emissions.[11] These environmental cost values can be used to compare the costs of continued fossil fuel use with the cost of investments in emission-reducing EVs. In addition, MPCA is "beginning to quantify the health and climate costs of vehicle emissions as well as the benefits from policies targeted at reducing these emissions, including the increased adoption of EVs."[12] Some factors that could be considered in a cost-benefit analysis of EVs include better grid management, public health, and other social benefits.

2. Evaluating Infrastructure Investments

In its comments, OAG proposed an "analytical tool" to assist the Commission in evaluating utility proposals to build EV charging infrastructure.[13] OAG explained the analytical tool as follows:

> Step one involves an analysis of the expected number of EVs expected within a state in a certain time period. This step includes analysis of economics and policy factors such as climate or air quality targets or EV adoption targets. Step two uses the information developed in step one to determine how much public charging infrastructure would be needed to support the projected levels of EV penetration including the type of chargers needed. There are existing resources for this task. For example, NREL has developed a tool to determine the level of infrastructure needs based upon population density, EV ownership rates, traffic patterns, and travel data. Step three is an assessment of the competitive market for charging infrastructure, to determine the ownership model for EV charging stations and the extent of utility involvement in the supporting infrastructure.[14]

[11] *See generally* Updating Environmental Costs Order.

[12] MPCA reply comments at 2.

[13] OAG comments at 13–14.

[14] *Id.*

This approach examines a number of factors to estimate the appropriate amount of infrastructure needed to support EVs, which can help avoid overbuilding infrastructure resulting in stranded assets.

3. Designing Effective Pilot Programs

Utilities occasionally propose pilot programs, which are temporary programs that allow the utility to test new technology or policies on a smaller scale. Pilot programs can be useful in the EV context because they allow utilities to experiment with different approaches to rate design, emerging technologies, infrastructure build-out, and other EV issues.

The purpose of a pilot is to determine whether a proposal is beneficial enough to warrant expansion to a full-scale program. A pilot proposal should articulate clear goals for the pilot and detail the evaluation metrics that will be used to measure and assess whether those goals have been met. Once the pilot has been adequately evaluated, the Commission can turn to the question of whether the approaches that were tested in the pilot should be expanded.

Furthermore, the scope and cost of a pilot will inform the level of scrutiny required before the Commission approves the pilot. For example, a smaller pilot may not require an extensive cost-benefit analysis before approval, because the smaller scale translates into a lower risk of adverse consequences if the expected benefits of the pilot do not materialize.

III. Commission Action

In the ordering paragraphs below, the Commission makes general and specific findings regarding EVs in Minnesota that are intended to shape and guide future EV proposals from utilities. The Commission affirms that EVs hold the potential for significant benefits to all Minnesota ratepayers, and that utilities will play a role in educating ratepayers about the benefits of EVs and helping integrate EVs into the electric system.

The Commission will require Minnesota's three investor-owned utilities—Minnesota Power, Otter Tail Power, and Xcel Energy—to submit the following filings, which are further described in the ordering paragraphs below:

Filing	Due Date
Report of planned 2019 EV proposals	March 31, 2019
Annual EV Reports required under Minn. Stat. § 216B.1614, subd. 3, including promotional cost recovery mechanisms	June 1, 2019
Transportation Electrification Plan	June 30, 2019
Proposals for infrastructure, education, managed charging, etc.	No later than October 31, 2019

The Commission will also request that MPCA file a supplemental report with the Commission in this Docket after it has completed its work quantifying the benefits of vehicle emission reductions related to EVs.

The Commission outlines in the ordering paragraphs below a number of topics that should be discussed in any future EV pilot proposal submitted by a utility, to the extent relevant.

The Commission will authorize the Executive Secretary to sustain an ongoing stakeholder process in this docket, further described below, which should seek to coordinate as much as practicable with the MPCA Volkswagen stakeholder process.

ORDER

The Commission makes the following general findings:

1. *Electrification Is In Public Interest*: The Commission finds that electrification of Minnesota's transportation sector can further the public interest in:

   a. *Affordable, economic electric utility service* by improving utility system utilization/efficiency and placing downward pressure on utility rates through increased utility revenues and better grid utilization;

   b. *Renewable energy use* by increasing electricity demand during hours when renewable energy is most prevalent on the system and developing tariffs that correlate renewable energy resources to electric vehicle charging; and

   c. *Clean energy* by reducing statewide greenhouse gas and other environmentally harmful emissions.

2. *Barriers to EV Adoption*: The Commission finds that barriers to increased EV adoption in Minnesota include but are not limited to: (a) inadequate supply of and access to charging infrastructure, and (b) lack of consumer awareness of EV benefits and charging options.

3. *Optimizing EV Benefits*: The Commission finds that how EVs are integrated with the electric system will be critical to ensuring that transportation electrification advances the public interest. This may include rate design that pairs charging with periods of low demand and high renewable energy generation, encourages advanced technology for enhanced load management, and provides direct benefits to EV owners through lower fuel costs of electricity.

4. *Utility Role Regarding EVs:* The Commission finds that Minnesota's electric utilities have an important role in:

   a. *Facilitating the electrification of Minnesota's transportation sector* through policies and investments that educate customers on the benefits of EVs and enhance the availability of charging infrastructure; and

b. *Optimizing the cost-effective integration of EVs* through appropriate rate designs, policies, and investments that improve system utilization/efficiency and benefit utility ratepayers, including non-EV owners.

The Commission makes the following specific findings:

5. *Expectations Regarding Utility Role:* The Commission finds that Minnesota's investor owned utilities should take steps to encourage the cost-effective adoption and integration of EVs. Among these steps, utilities should:

   a. *Focus specifically on issues related to transportation electrification*, including the cost-effective integration of EVs.

   b. *Develop and file EV-related proposals* intended to encourage the adoption of EVs by:

      i. Expanding the availability of charging infrastructure, both home and public;

      ii. Enhancing consumer awareness of EV benefits and charging options beyond what utilities could otherwise do under Minn. Stat. § 216B.1614, subd. 2(c)(2), without specific Commission approval; and

      iii. Facilitating the electrification of vehicle fleets.

   c. *Encourage environmentally and economically optimal EV integration* through, at a minimum, the adoption of appropriate and effective time-of-use and EV-specific rate designs, and reasonable initiatives or investments that encourage and support smart charging.

   d. *Consider energy bill financing as an option*, at least on a pilot basis, to facilitate the economic availability of residential charging infrastructure.

6. *Content of EV-Related Proposals/Investments:* The Commission finds that the following should be included at a minimum in any EV-related utility proposals:

   a. *Any EV-related proposals that involve significant investments* for which the utility is seeking or will seek cost recovery should include a cost-benefit analysis that shows the expected costs along with the expected ratepayer, system and societal benefits associated with the proposal; and

   b. *In the case of a proposed pilot*, the utility filing should include specific evaluation metrics for the pilot and identify what the utility expects to learn from the pilot. An extensive cost-benefit analysis may not be needed for a pilot, depending on the scope and cost of the pilot.

7. *Cost-Benefit Analysis:* The Commission finds that no specific cost-benefit methodology should be adopted at this time. However, as a starting point, utilities should use the Commission's current environmental externality values for carbon and criteria pollutants in analyzing the societal costs and benefits associated with EV-related proposals. Cost-benefit analyses should consider potential long-term ratepayer and societal benefits,

including better grid management, public health, and other social benefits. These analyses should also consider potential long-term costs, including the risk of stranded investment.

8. *Evaluating Investments in Public Charging Infrastructure:* The Commission finds that the OAG's suggested three-step process for evaluating utility investments in public charging infrastructure is reasonable. This framework should be incorporated into a utility's analysis when seeking Commission approval of any such investments.

9. *Interoperability:* The Commission finds that utility investments and arrangements related to charging infrastructure should be designed to ensure interoperability, using standards such as Open Charge Point Protocol and Open Automated Demand Response.

10. *Utility Cost Recovery*: The Commission finds that no single method of cost recovery should be generally precluded at this time for any EV-related investments. Rather, cost recovery, including the method of recovery, should be determined in each individual case based on factors such as the purpose, nature, magnitude, and potential benefits of the investments.

11. *Promotional Cost Recovery:* The Commission also finds that Minn. Stat. § 216B.1614, subd. 2(c)(2), allows utilities the opportunity to recover costs related to educating customers on the benefits of EVs beyond those costs related specifically to the utility's EV tariffs.

The Commission takes the following actions:

12. Minnesota Power, Otter Tail Power, and Xcel Energy shall file EV promotional cost recovery mechanisms consistent with Minn. Stat. § 216B.1614, subd. 2(c)(2), and the Commission's above Findings in this docket, as part of their annual EV reports filed June 1, 2019.

13. The Commission requests that the MPCA file a supplemental report with the Commission in this Docket after it has completed its work quantifying the benefits of vehicle emission reductions related to EVs.

14. The Commission directs Minnesota Power, Otter Tail Power, and Xcel Energy to file:

    a. By March 31, 2019, a report that identifies and discusses the EV-related proposals the utility plans to file in 2019, including the approximate date the utility anticipates filing those proposals; and

    b. By June 30, 2019, a Transportation Electrification Plan identifying what EV-related initiatives the utility is contemplating over the next two years, including next steps as specific programs to scale up current or currently proposed EV pilots or tariffs. The plan should identify the extent to which the utility's planned or contemplated initiatives would:

i. Facilitate availability and awareness of public charging infrastructure and residential charging options for both single family and multiple unit dwellings, including programs or tariffs in development to address flexible load or reduce metering and data costs;

ii. Educate customers on the benefits of EVs;

iii. Assist in the electrification of vehicle fleets with a focus on medium and heavy duty trucks and buses;

iv. Offer DCFC specific tariffs and which tariffs are currently in use;

v. Optimize EV benefits by, for example, aligning charging with periods of lower customer demand and higher renewable energy production and by improving grid management and overall system utilization/efficiency; and

vi. A discussion of current and planned charging practices/tariffs for public charging stations along with a discussion of any concerns related to those charging practices.

15. Minnesota Power, Otter Tail Power, and Xcel Energy shall file proposals, which can be pilots, intended to enhance the availability of or access to charging infrastructure, increase consumer awareness of EV benefits, and/or facilitate managed charging or other mechanisms that optimize the incorporation of EVs into the electric system. The utilities should consult with stakeholders, including but not limited to the Department, OAG and Fresh Energy, to help with the development of their proposals. The Executive Secretary is authorized to work with the utilities in identifying specific due dates for each filing, which should be sequenced to accommodate workload issues of Commission staff, Department of Commerce and other stakeholders. These proposals must be filed no later than October 31, 2019.

16. In any future pilot proposal, utilities should include a discussion of the following topics to the extent relevant:

a. Environmental justice, with a focus on communities disproportionately disadvantaged by traditional fossil fuel use;

b. Low-income access and equitable access to vehicles and charging infrastructure, which can include all-electric public transit and EV ride-sharing options;

c. Environmental benefits, including but not limited to carbon and other emission reductions;

d. Potential economic development and employment benefits in Minnesota;

e. Interoperability and open charging standards;

f. Load management capabilities, including the use of demand response in charging equipment or vehicles;

g. Energy and capacity requirements;

h. Pilot expansion and/or transition to permanent status at a greater scale;

i. Education and outreach;

j. Market competitiveness/ownership structures;

k. Distribution system impacts;

l. Cost and benefits of the proposal;

m. Customer data privacy and security; and

n. Evaluation metrics and reporting schedule.

17. The Commission authorizes the Executive Secretary to sustain an ongoing stakeholder process in this Docket, led by Commission staff, that involves a broad and diverse range of participants. The Commission specifically authorizes the Executive Secretary, when necessary and at the appropriate time, to solicit written comments and/or establish stakeholder workshops to examine any of the issues raised in this Docket. The Executive Secretary is also authorized to establish a notice and comment process for stakeholder input in response to each utility Transportation Electrification Plan. This stakeholder process should seek to coordinate as must as practicable with the MPCA Volkswagen stakeholder process and their grant program.

18. This order shall become effective immediately.

BY ORDER OF THE COMMISSION

Daniel P. Wolf
Executive Secretary

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BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

Katie J. Sieben	Chair
Dan Lipschultz	Commissioner
Valerie Means	Commissioner
Matthew Schuerger	Commissioner
John A. Tuma	Commissioner

In the Matter of Xcel Energy's Petition for Approval of Electric Vehicle Pilot Programs

ISSUE DATE: July 17, 2019

DOCKET NO. E-002/M-18-643

ORDER APPROVING PILOTS WITH MODIFICATIONS, AUTHORIZING DEFERRED ACCOUNTING, AND SETTING REPORTING REQUIREMENTS

PROCEDURAL HISTORY

On October 12, 2018, Xcel Energy (Xcel) filed a petition requesting approval of two electric vehicle (EV) pilot programs, a Fleet EV Service Pilot and a Public Charging Pilot.

By February 1, 2019, the Commission received comments on the proposals from the following:

- City of Hastings
- SemaConnect, Inc
- Alliance of Automobile Manufacturers; the Association of Global Automakers; American Honda Motor Co., Inc.; Audi of America; Ford Motor Company; General Motors LLC; Hyundai Motor Company; Kia Motor Corporation; and Mitsubishi Motors R&D of America, jointly
- Alliance for Transportation Electrification
- Siemens
- Institute for Local Self-Reliance (ILSR)
- Greenlots
- the Department of Commerce, Division of Energy Resources (the Department)
- City of Minneapolis
- the Office of Attorney General, Residential Utilities and Antitrust Division (OAG)
- Citizens Utility Board of Minnesota (CUB)
- Tesla, Inc. (Tesla)
- Minnesota Sierra Club Supporters
- Department of Administration
- Xcel Large Industrials (XLI)

- Fresh Energy, Minnesota Center for Environmental Advocacy, Natural Resources Defense Council, the Sierra Club, and the Union of Concerned Scientists, jointly (Clean Energy Organizations)
- Pollution Control Agency (PCA) and Department of Transportation (MnDOT), jointly
- ChargePoint, Inc. (ChargePoint)
- approximately 64 public commenters

By February 15, 2019, the Commission received reply comments from the following:

- Greenlots
- Xcel
- the Department
- CUB
- the OAG
- Tesla
- the Clean Energy Organizations
- ChargePoint
- Pollution Control Agency
- XLI
- Siemens

On April 11, 2019, the Pilot proposals came before the Commission.

FINDINGS AND CONCLUSIONS

I. Introduction

In 2014, the Legislature adopted Minn. Stat. § 216B.1614, which establishes requirements for engaging public utilities in the electrification of the transportation sector. Under the statute, "each public utility selling electricity at retail must file with the commission a tariff that allows a customer to purchase electricity solely for the purpose of recharging an electric vehicle."[1] The tariff must be available to the residential class.[2] The statute also authorizes a cost-recovery mechanism to allow a utility to recover costs "reasonably necessary to comply" with the statute, as well as costs related to informing and educating "customers about the financial, energy conservation, and environmental benefits of electric vehicles."[3]

In response to this directive, Xcel filed, and subsequently received Commission approval of its EV charging tariff, which established the rates to be charged to residential customers, consistent

[1] Minn. Stat. § 216B.1614, subd. 2.

[2] *Id*. at subd. 2 (a) (3).

[3] *Id*. at subd. 2 (c) (2).

with the Legislature's directive.[4] Since the development and implementation of its tariff, Xcel has taken additional steps to further advance the Legislature's policy objective to increase EV usage and ownership, including its proposal of two EV pilot programs in this docket.

The first pilot is a Fleet EV Service Pilot, which would authorize Xcel's investment in installing and maintaining EV infrastructure for fleet operators (entities using groups of EVs). Xcel estimated that over 700 charging ports would be installed as part of this pilot program, and the Company expects to initially serve three customers: Metro Transit; the Department of Administration; and the City of Minneapolis.

The second pilot is a Public Charging Pilot, which would authorize Xcel's investment in installing and maintaining EV infrastructure for site hosts and developers of public fast-charging stations[5] along corridors within Xcel's service territory, as well as for a network of EV community mobility hubs.

II. The General EV Docket

A number of stakeholders cited the Commission's recent decisions in the General EV Docket[6] as a basis for requiring specific action of Xcel in this proceeding, including the filing of a cost-benefit analysis. The purpose of the General EV Order is to shape and guide utility proposals, considering the importance of transportation electrification and its potential benefits to ratepayers. Utilities are specifically encouraged to make filings aimed at expanding charging infrastructure, facilitating fleet vehicle electrification, and enhancing consumer awareness.

The General EV Order, which was issued more than one year after Xcel's initial filing in this case and on the cusp of the Commission's consideration of this petition, also established filing requirements for utilities. By June 30, 2019, Xcel, as well as Minnesota Power and Otter Tail Power, must file a Transportation Electrification Plan identifying EV-related initiatives the utility is contemplating and an analysis of how those initiatives would achieve EV-related objectives.

The Commission encouraged utilities to include in their individual proposals a cost-benefit analysis to examine long-term ratepayer and societal benefits, as well as potential costs, but the Commission did not adopt a particular cost-benefit methodology. Further, the Commission determined that cost recovery should be decided on a case-by-case basis considering various factors, such as the purpose, nature, magnitude, and potential benefits of the investments.

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[4] *In the Matter of Northern States Power Company d/b/a Xcel Energy's Petition for Approval of a Residential Electric Vehicle Charging Tariff*, Docket No. E-002/15-111, Order Approving Tariffs and Requiring Filings (June 22, 2015).

[5] Fast charging stations use direct current chargers that offer a faster charging timeline of typically between 10 and 30 minutes.

[6] *In the Matter of a Commission Inquiry into Electric Vehicle Charging and Infrastructure*, Docket No. E-999/CI-17-879, Order Making Findings and Requiring Filings (February 1, 2019) (the General EV Order).

III. Xcel's Petition

In its petition in this case, Xcel stated that its overarching objective is to reduce greenhouse gas emissions and air pollution, while making efficient use of the electric grid and maintaining low bills for ratepayers. Xcel explained that use of pilot programs reasonably limits each program's scope and potential ratepayer impacts, and enables the Company to test, measure, and verify key assumptions before making the programs available on a larger scale.

Xcel developed its pilot proposals following a stakeholder process involving various non-profit organizations, state agencies, corporations, and utility companies. Great Plains Institute helped facilitate five workshops, which were aimed at understanding transportation electrification; identifying proposed solutions; and developing metrics to evaluate pilot success.

The petition includes each pilot program's objectives and budgets, as well as the Company's rate design proposal, proposed annual reporting metrics, and deferred accounting request. Further, Xcel stated that in developing the proposed pilots, the Company also took into consideration the comments filed in the EV General Docket, the experience of other utilities around the country, and the input of customers and stakeholders.

Ultimately, the majority of parties supported Xcel's petition; several offered recommended modifications to improve the pilot programs. The OAG and XLI recommended that the Commission deny the petition.

A. Fleet Electric Vehicle Service Pilot

The EV Fleet Service pilot would be available to non-residential customers operating fleets of light-, medium-, or heavy-duty EVs. Initially, Xcel expects three entities – Metro Transit; the Department of Administration; and the City of Minneapolis – to participate.

Xcel stated that the Company proposed this pilot because the fleet market has a diversity of vehicles; is focused on economic value; is motivated to reduce greenhouse gas emissions and improve air quality; and has the volume of vehicles to make larger strides toward transportation electrification. Xcel stated that although the Company has existing residential EV service offerings, adding the Fleet EV Service pilot would, as EV expansion evolves, deepen the understanding of EV system benefits and how to best socialize costs. Under this pilot, Xcel would own install, own, and maintain infrastructure, and if requested by a participant, would also install, own, and maintain charging equipment.

This pilot's proposed budget is $14.4 million over a three-year term. Details of the proposed budget are shown in the table below.

TABLE 1			
Estimated Fleet EV Service Pilot Budget			
Cost Item	Capital	O&M	Total
EV Service Connection	$1,864,000	$30,000	$1,894,000
EV Supply Infrastructure and Charging Equipment	$9,396,000	$457,000	$9,853,000
Installation Management (includes construction management, design engineering, and legal agreement review)	-	$575,000	$575,000
Advisory Services and Outreach, including Analytics Services	-	$1,163,000	$1,163,000
Program Management	-	$735,000	$735,000
IT	-	$175,000	$175,000
TOTAL	**$11,260,000**	**$3,135,000**	**$14,395,000**

B. Public Charging Pilot

Under Xcel's proposed Public Charging pilot, the Company would install EV infrastructure for site hosts and developers of public charging stations along corridors and at community mobility hubs. Under this pilot, Xcel would own install, own, and maintain infrastructure but would not own or maintain any charging equipment. Xcel stated that public charging is a critical element of expanding the EV market because it supports longer distance driving and makes charging available to those who do not charge EVs at home.

This pilot's offerings are twofold. The first is the development of community mobility hubs; Xcel has partnered with the Cities of St. Paul and Minneapolis for the development of community mobility hubs, with HOURCAR providing a car-sharing service at charging locations in the area. These hubs would make charging available to the public and to transportation network companies, such as Lyft and Uber.

The second offering of this pilot is aimed at, but not limited to, applicants seeking funds from Minnesota's Diesel Replacement Program, which is funded by the Volkswagen Environmental Mitigation Settlement and administered by the PCA. These funds will be used to develop fast-charging stations at corridors within Xcel's service territory, with the goal of expanding the EV market by broadening access to charging stations, which would in turn alleviate impediments to long-range driving.

Under this pilot, Xcel expects to facilitate installation of approximately 350 publicly accessible charging ports.

This pilot's proposed budget is $9.2 million over a three-year term. Details of the proposed budget are shown in the table below.

TABLE 2			
Estimated Public Charging Pilot Budget			
Cost Item	Capital	O&M	Total
EV Service Connection	$2,019,000	$29,000	$2,048,000
EV Supply Infrastructure	$5,781,000	$87,000	$5,868,000
Installation Management (includes construction management, design engineering, and legal agreement review)	$0	$575,000	$575,000
Marketing and Outreach	$0	$60,000	$60,000
Program Management	$0	$555,000	$555,000
IT	$0	$95,000	$95,000
TOTAL	**$7,800,000**	**$1,401,000**	**$9,201,000**

C. Pilot Similarities

Although the two pilots are fundamentally different, they do share certain characteristics.

First, Xcel proposed to waive its tariff provisions governing Contributions In Aid of Construction (CIAC).[7] Generally, CIAC governs the cost of service connection installation, of which customers pay a portion. CIAC provisions apply to the general provision of service, for which costs and revenues are known.[8] In this case, the CIAC waiver would apply to make-ready infrastructure.[9] The Company stated that it does not have accurate estimates of costs and revenues related to EV charging and usage and is therefore unable to determine an accurate customer contribution amount for make-ready infrastructure under the pilots, which are intended to study this and other issues related to EV expansion.

Second, Xcel proposed to treat its capital investments in make-ready equipment as utility plant cost items in its Federal Energy Regulatory Commission (FERC) distribution plant accounts (FERC account 182.3). FERC authorizes a utility to include in that account the cost of installed equipment on the customer's side of the meter when the utility incurs such cost and retains title to, and is responsible for, the maintenance and replacement of such property. The proposed

[7] Xcel Energy Minnesota Electric Rate Book, Section 6, Sheets 22 et. seq.

[8] The CIAC formula is used to determine the customer contribution amount, which is not collected by the utility through revenues.

[9] Xcel defines "make-ready" infrastructure to include: a dedicated service connection for EV charging, along with necessary transformer upgrades, service conductors, and meters. It also includes EV supply infrastructure, such as new service panels, conduits, and wiring up to the charger. In this order, the Commission uses the term with the meaning given by Xcel. Under the Fleet EV Service pilot, customers may request that Xcel provide, install, and maintain chargers, and Xcel has accordingly proposed to recover these costs through either a monthly EV Charger Service charge, or, at the election of the customer, an up-front payment.

classification would allow Xcel to include the investments in rate base in its next general rate case filing.[10]

Third, customers under either pilot would be charged for electric usage according to Xcel's existing general service time-of-day (TOD) rates, which are based on a 12-hour on-peak period between 9:00 a.m. and 9:00 p.m. (also known as a 2:1 energy rate differential ratio). Under the Public Charging Pilot, customers, i.e., site hosts, would not, however, required to pass the TOD rates onto drivers who use the EV charging stations. In addition to the TOD rates, customers in both pilots would be charged a minimum monthly bill based on the number of ports installed.

Fourth, Xcel's petition requests deferred accounting treatment of costs related to Operations and Maintenance (O&M) expenses and depreciation expense related to capital investments in the make-ready infrastructure.

IV. Pilot Approval

There is widespread support for Xcel's petition from parties and from members of the public who commented. The OAG and XLI opposed the petition. The Department and CUB took no position on whether the pilots should be approved but made recommendations on specific aspects of the proposals, which are discussed separately below.

A. Comments in Support of the Proposed Pilots

1. The Clean Energy Organizations

The Clean Energy Organizations recommended Commission approval of both pilot programs, stating that transportation electrification would significantly reduce greenhouse gas emissions and help achieve state targets for emissions reductions (citing a report by the Pollution Control Agency and Department of Commerce that states that transportation is the largest source of greenhouse gas emissions in Minnesota).

They also maintained that EVs would have enormous health benefits by reducing pollution-related health issues (citing Department of Health estimates that particulate matter and ozone pollution contribute to 2,000 deaths annually in the Twin Cities metropolitan area). Both pilots, they stated, would advance these goals while reasonably protecting ratepayers, as the proposals are modest in size with limited budgets.

Further, they stated that the proposed pilots promote effective grid utilization by incentivizing charging during off-peak periods. They also stated that any opposition to the budgets is unfounded, and that the budgets, if anything, are too small to sufficiently bolster EV expansion.

In particular, they highlighted the need for public support and utility intervention in the development of public charging stations, which are not economically viable without decisive action to approve EV programs, such as Xcel's proposed Public Charging pilot. They asserted that expanding the EV charging network is critical to making EVs a favored alternative to gasoline- and diesel-fueled vehicles.

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[10] Xcel's proposed classification would include charging equipment provided by Xcel under the Fleet EV Service pilot, although pilot participants would pay their portion of those costs.

They were equally supportive of the proposed Fleet EV pilot program, stating that a fleet EV transit system, such as Metro Transit, will increase the visibility of EVs, enticing riders to purchase EVs for individual use as well. Further, transit buses travel an average of 34,000 miles per year, compared to 11,000 for light-duty vehicles, resulting in more substantial environmental benefits. They noted that any unanticipated complications under either pilot would be a valuable learning tool as EV expansion continues.

2. EV Industry Proponents

The Alliance of Automobile Manufacturers, Tesla, Greenlots, ChargePoint, SemaConnect, Siemens, and the Alliance for Transportation Electrification are variously involved in the manufacturing of EVs or the development of related equipment, products, and services, and they voiced overwhelming support for Xcel's proposed pilot programs.

These stakeholders endorsed the pilot programs' objectives outlined in Xcel's petition and recommended that the Commission approve the proposals. They emphasized the role of utilities in expanding the EV market by developing EV programs that increase grid efficiency and provide ratepayer benefits. They stated that EV load is generally flexible (meaning that charging can occur at optimal times because batteries store the electricity rather than immediately use it). Moreover, adding EV load to the system has the potential to reduce system-wide energy costs if coupled with effective rate structures. They also asserted that because the proposals will explore the central role of utilities in deployment of EV infrastructure at scale, the outcomes will provide valuable information on how utility infrastructure investments affect the EV market and how to increase the effectiveness of the utility's role.

3. Pilot Participants

The Department of Administration, the City of Minneapolis, and Metro Transit, prospective participants in the Fleet EV Service pilot, supported Commission approval of the petition. They stated that the pilot programs would create a sustainable path toward lowering electricity costs for ratepayers, meeting climate goals, and improving health impacts associated with transportation.

4. PCA and MnDOT

The PCA and MnDOT recommended Commission approval of the pilot programs, stating that utility investment in advancing electric vehicles is critical to achieving the agencies' goals of developing a multimodal transportation system that maximizes the health of people, the environment, and the state economy. They also stated that utility infrastructure investments would likely help stretch the VW funding to increase the number of public charging stations.

B. Comments in Opposition to the Proposed Pilots

1. The OAG

The OAG recommended that the Commission deny the petition and direct Xcel to refile its proposed pilots at the time of its June 2019 Transportation Electrification Plan.[11] The OAG

[11] The Plan must be filed by June 30, as directed by the Commission in the EV General Docket.

recommended several changes to the current proposal, including a rate design with more effective price signals. The OAG also recommended that a modified proposal should remove the request to waive CIAC provisions, remove the deferred accounting request, and remove the proposal for utility ownership of make-ready infrastructure beyond the meter. The OAG stated that these changes would shift the cost risk of the pilots away from ratepayers.

The OAG disputed that the proposed budgets are acceptable, stating that the proposed capital budget of $19.1 million for both pilots is unreasonably high due to the Company's CIAC waiver request.

2. XLI

XLI recommended that the Commission deny the petition because the pilot proposals would require ratepayers to subsidize investments that are more appropriately made by private businesses, and because the proposals exceed the Legislature's policy objectives. XLI argued that the structure of the pilot proposals requires ratepayer funding with little return on the investment.

XLI also claimed that Xcel has not demonstrated that the proposed pilots would produce environmental benefits as intended and that investing ratepayer dollars to generate increases in EVs is speculative. XLI recommended that Xcel take steps to support transportation electrification through customer education and advanced rate design to address increases in demand caused by more EVs.

C. Commission Action

The Commission concurs with parties supporting Xcel's petition. The two proposed pilots advance the legislative goal of increasing transportation electrification in a manner that reasonably limits potential rate impacts, while presenting an opportunity for ratepayers and the public to benefit. The Commission is not persuaded that requiring Xcel to file a new petition would do more than delay implementation of these pilots.

Xcel engaged in a meaningful stakeholder process in which a wide range of input was provided, and the Company then took that input into serious consideration when developing its proposals. As a result, the proposals are limited in duration – three years each, and are limited in budget size as needed to achieve the projected increases in fleet EVs and public charging. Together, both pilots are estimated to facilitate the installation of approximately 1,000 charging ports, of which approximately 350 will be publicly accessible. These parameters reasonably balance the commitment to EV expansion and the ratepayer cost of those efforts. Furthermore, any future cost recovery-related filings will be separately scrutinized and considered by the Commission. Additionally, Xcel intends to take the following steps if the pilots are approved: host semi-annual advisory committee meetings with a facilitator; provide data on key metrics in an annual filing; and engage third-party evaluators to conduct an interim and final evaluation. These steps provide helpful continuity between the implementation and subsequent review of the programs.

Further, Xcel's proposal is for two limited-duration pilot programs. As discussed in greater detail below, the Commission will require Xcel to file reports on pilot performance, which the Commission will review before making a decision on whether to continue or expand the programs.

For all these reasons, the Commission will approve the proposed pilots, with modifications as discussed in further detail below.

V. Key Pilot Features

Parties differed on key aspects of the pilot proposals, including the following: wavier of CIAC provisions; the classification of make-ready infrastructure costs; and the pilots' TOD rate structure. These issues are addressed below.

A. Contribution in Aid of Construction

Xcel's proposal included a request to waive its applicable CIAC provisions for both pilots because the Company stated that it could not determine the expected usage of participating customers and corresponding revenue needed to accurately calculate the amount of the customer contribution. Without the waiver, Xcel stated that pilot participants would be required to finance the make-ready infrastructure costs independently, potentially upending pilot participation.

1. Positions of the Parties

The Department recommended that the CIAC waiver request be granted for certain infrastructure. Other parties either supported or opposed the CIAC wavier as proposed.

a. The Department

The Department appeared to take the nuanced approach that infrastructure that is not ordinarily owned by the utility is not subject to the Company's CIAC provisions and therefore no waiver is required for the installation costs of that infrastructure. The Department did, however, support waiver of CIAC provisions for infrastructure that *is* ordinarily utility-owned.

The Department reasoned that the line of demarcation between utility– and customer–owned infrastructure is the point of service connection and that under the pilot, Xcel's proposal to include make-ready infrastructure in that designation is beyond what is traditionally included in determining cost allocation. The Department stated that although the CIAC provisions do not apply to equipment beyond the utility's point of service connection, the waiver request should otherwise be approved.

b. Clean Energy Organizations, ChargePoint, Greenlots, Tesla, and the Alliance for Transportation Electrification

The Clean Energy Organizations, ChargePoint, Greenlots, Tesla, and the Alliance for Transportation Electrification all voiced support for Xcel's proposal to waive the applicable CIAC provisions, asserting that under these circumstances, the request is warranted. They stated that the CIAC formula is not designed with EV usage in mind, and that the smaller volumetric load per EV is therefore not reflected in the calculation.

They also stated that a CIAC waiver would be, in effect, moderated by the limited duration and budget of each pilot, thereby minimizing the impact on ratepayers. Further, they contended that reducing up-front costs through utility investments is essential to fulfilling program objectives and encouraging participation.

c. The OAG, CUB, and XLI

The OAG, CUB, and XLI opposed waiver of the CIAC provisions, stating that granting the request would weaken ratepayer protections by over-subsidizing participating customers. They claimed that waiving the provision is not offset by clear and obvious benefits to ratepayers through system improvements.

They described the pilot investments as large-scale with no clear estimation of expected revenues. They argued in favor of applying traditional cost causation principles in which customers incurring upfront infrastructure costs pay the portion of those costs that the utility would not otherwise recover through its revenues. XLI further contended that a utility's ownership of EV charging infrastructure behind the meter is not within the scope of utility service because it is different from what is ordinarily associated with providing electric service to customers. XLI claimed that Xcel's proposal is an expansion of the utility's role beyond what the Legislature either authorized or envisioned.

d. Xcel

In response to issues raised, Xcel stated that based on its initial observations, potential pilot participants are cost-sensitive and that the Company's proposed investments are a factor affecting participation levels. Xcel also emphasized that ratepayers are expected to benefit from the pilots, both through increased revenues, as well as environmental benefits, and that the data gleaned from the pilots will inform future programs and proposals.

Contrary to claims that the provision of service using make-ready infrastructure is outside the range of what a utility ordinarily provides, Xcel stated that the test for determining whether equipment qualifies as utility distribution plant, i.e., utility equipment, is not its location in relation to the meter, but whether it is "used and useful in rendering service to the public."[12] Xcel also asserted that some degree of departure from ordinary practices is warranted as a means of furthering the goals of electrification of the transportation sector.

2. Commission Action

The Commission concurs with parties who support Xcel's request to waive the CIAC provisions. While the issues raised by those opposing the waiver are relevant considerations, it is important to view the request within the context of each pilot, its duration, and its budget.

The limited terms of the pilots and their reasonable budgets ultimately limit the impact to ratepayers. In the event pilot budgets are reached prior to the end of the three-year term, Xcel will not accept additional participants; the Company has committed to staying within the budgets proposed. Further, Xcel has made a persuasive argument that the customer's CIAC contribution cannot be accurately calculated without knowledge of EV charging and revenues.

The Commission recognizes that the existing CIAC policies were developed to protect ratepayers from excessive and unreasonable costs. But to foster growth of EVs for the purpose of transportation electrification requires a forward-thinking approach. Utilities are at the forefront of this effort. Although the pilots could ultimately lead to an understanding that advancing EVs

[12] Minn. Stat. § 216B.16, subd. 6.

requires no refinement of the traditional cost-causation approach, such an outcome is merely one possibility and is an issue the pilots are intended to study. Facilitating expansion of EVs necessarily requires the installation of equipment not typically installed. This is a new arena, and as Xcel aptly pointed out, it warrants a limited departure from ordinary practices.

Furthermore, as pilots, they are intended to be instructive on the propriety of cost allocation and cost recovery for this infrastructure, and they will provide data that will aid subsequent evaluation of the pilots' costs and effectiveness.

For all these reasons, the Commission will authorize a waiver of CIAC service policy provisions, and other customer contributions, for the three-year term of the pilots. The Commission will also direct Xcel to use its current CIAC formula to determine the amount of subsidy a participant would receive and then track and report these costs for each pilot, including revenues.

B. Classification of Make-Ready Infrastructure Costs

Xcel proposed to treat its capital investments in make-ready infrastructure for both pilots as cost items in its FERC distribution plant accounts. This accounting treatment would enable Xcel to include the amounts in base rates in the Company's next general rate case.

1. Positions of the Parties

Parties differed on this issue for reasons similar to those discussed above.

a. The Department

The Department recommended that if the Commission authorizes classification of equipment that Xcel does not ordinarily own as utility distribution plant, the Commission should limit pilot participation to public entities.

b. The Alliance for Transportation Electrification, Greenlots, Tesla, ChargePoint, PCA and MnDOT,

These parties supported Xcel's proposal, stating that the pilots are modest in scope and that the proposal would foster regulatory certainty and help spur economic innovation in the transportation sector.

They also stated that utility ownership of EV charging infrastructure is likely necessary to make financing possible for pilot participants, particularly fleet participants and that the proposed structure would accelerate EV market growth by alleviating financial barriers to EV expansion. Without utility ownership of make-ready infrastructure, they asserted that the likely pool of eligible participants would be scaled back. They also asserted that utility infrastructure investments would likely help stretch VW funding to increase the number of public charging stations.

c. The OAG and XLI

The OAG and XLI opposed treating make-ready infrastructure as utility distribution plant, stating that the existing utility-customer demarcation point balances the system benefits of each new customer with that customer's cost responsibility for new service.

They also stated that because Xcel intends to contract with third-parties to conduct engineering and maintenance of that equipment, the Company is outside its area of expertise. Instead, they maintained that a competitive EV market ~~that supports a competitive market~~ for the provision of such services is a better option. Further, they argued that Xcel should rely on revenues from pilot participants to recover its make-ready infrastructure costs, rather than impose those costs on ratepayers.

XLI also argued that allowing Xcel to own infrastructure beyond the meter would be an expansion of the utility's traditional role, and that it would be more reasonable for Xcel to conduct such business through an unregulated affiliate.

d. Xcel

Xcel stated that the make-ready infrastructure, including service panels, conduit, and wiring, is not likely to change over time and is not different in kind from the infrastructure installed up to the charging stubs. The Company stated that there is no basis for imposing a location-based test for determining whether the equipment is utility equipment, particularly in light of the fact that there is no law prohibiting such ownership and that the applicable legal standard is whether the equipment is used and useful in rendering service to the public.

2. Commission Action

The Commission will approve Xcel's proposed classification of its make-ready infrastructure as utility distribution plant in this case. One key purpose of the pilots is to investigate the extent to which socializing the costs of this EV-related infrastructure will encourage EV adoption, and to measure the benefit that increased EV adoption provides to ratepayers. This purpose would be unattainable if Xcel were not allowed to classify these infrastructure investments as utility distribution plant. Therefore, Xcel's proposal to install, maintain, and own infrastructure is an essential and necessary part of these pilots. As a result, it is therefore reasonable under these circumstance to authorize Xcel to classify its make-ready infrastructure as requested. More specifically, these proposed infrastructure investments in the context of these pilots will help the Commission and stakeholders evaluate the extent to which these investments will benefit the public.

The Commission will therefore approve Xcel's request to classify its make-ready EV infrastructure investments as utility distribution plant for both pilots, and will approve Xcel's request to own charging equipment provided under the bundled service option in the Fleet EV Service Pilot. This classification is limited to EV infrastructure investments and charging equipment installed during the pilots.

The Commission is also acutely aware, however, of the importance of approving programs that are as sound as possible and do as much as possible to advance the broad public interest. While the Commission does not adopt the Department's specific recommendation, the Commission will direct Xcel to consider geographic and customer diversity in its selection of additional participants in the Fleet EV Service pilot. Of the additional participants, one must be a public entity with a primary location outside Ramsey and Hennepin Counties. Further, no more than one of the additional participants may be a private or non-profit entity.

C. The TOD Rate Structure

Xcel's petition applies a TOD rate structure to participants in both pilots that includes an off-peak period between 9:00 p.m. and 9:00 a.m. Customers would also incur a demand charge applied to the highest 15-minute peak kilowatt (kW) load during a month. Total demand charges are limited according to the kWh energy used during the month, using a calculation that divides the amount of kilowatt hours (kWh) energy used during the month by 100 hours.

Under the Public Charging pilot, public charging stations would be billed according to this rate structure, but Xcel's proposal does not condition their participation in the pilot on their agreement to pass the TOD rates onto to EV customers using the charging stations.

The Clean Energy Organizations recommended two related pilot modifications. First, they recommended that the Commission direct Xcel to require that charging stations in the Public Charging pilot pass the TOD rates onto their customers, EV drivers. Second, in response to disagreement over Xcel's proposed TOD rate structure, they recommended that the Commission initiate a separate proceeding to examine rate structures of Xcel's Commercial and Industrial customer class to better understand whether permanent changes to the existing rate structure are warranted. These two issues are discussed below.

1. Public Charging Stations

a. Positions of the Parties

i. Clean Energy Organizations

In recommending that public charging stations be required to pass the TOD rates through to their customers, the Clean Energy Organizations emphasized the need to encourage efficient grid management by incentivizing drivers to charge their EVs during off-peak periods. This, they said, consequently maximizes cost savings. They stated that unless drivers are incentivized by price, they are much more likely to charge their EVs when it is convenient, rather than when it is most effective in terms of grid utilization. They recommended that Xcel make the TOD rate the default arrangement with public charging stations.

ii. ChargePoint and Tesla

ChargePoint and Tesla adamantly recommended that site hosts retain the flexibility to set pricing that reflects cost components other than the energy cost. They said that such flexibility spurs market competition and ensures that charging stations are able to recover their costs, including the cost of operating a charging station, as well as the fixed costs of charging equipment. This, in turn, helps develop a more innovative and cost-effective market.

They also stated that the recommendation of the Clean Energy Organizations is problematic for several other reasons. They maintained that pricing will vary based on incentives established by charging stations to entice customers, depending on the station's location and business hours, among other factors. Charging behavior also depends, they claimed, on the needs of individual drivers and their accessibility to charging stations commercially or at home. They further stated that pricing restrictions do not achieve better grid utilization if, for example, drivers are not incentivized to leave when the charge is finished. In such a case, charging availability is reduced, preventing other drivers from using the service.

They also disputed that there is a clearly demonstrated effectiveness of price signals, stating that there is insufficient data available to conclusively show that driving behavior is affected by pricing alone. Charging station operators, they asserted, are sophisticated market participants and are in the best position to know how to set prices.

iii. CUB

CUB made the general comment that it is reasonable for the Commission to establish certain contingencies that would be set forth in Xcel's agreements with pilot participants who benefit from ratepayer funds. Those contingencies could address important program features, such as rate structures that are likely to affect the successful use of ratepayer funds. CUB stated that the advantages of price signals are lost if not passed onto drivers.

iv. Xcel

Xcel did not propose to require charging stations to charge their customers TOD rates, stating that maintaining pricing flexibility is important. Xcel also concurred, however, on the importance of using TOD rates, acknowledging that charging during off-peak hours increases sales while reducing the need for additional resources to support peak demand. To address this issue, Xcel proposed to include a provision in its agreements with public charging stations suggesting that TOD rates be passed through to drivers. Xcel also recommended requiring public charging stations to provide data on their rates and fees to enable further examination of this issue. Xcel would include this data in its annual report on the pilot.

b. Commission Action

The Commission concurs with parties on the importance of minimizing ratepayer costs while incentivizing participation in these programs that were developed with the understanding that effective grid utilization will help keep costs down in the near-term and that reducing greenhouse gas emissions will produce both environmental and economic benefits in the long-term. With this in mind, protecting ratepayer interests requires a modified approach to strongly encourage charging stations to effectively incentivize their customers in a way that aligns with the pilot's objectives.

The Commission will therefore modify the Public Charging pilot by directing Xcel to condition participation on agreement by site hosts to have a default time-differentiated rate structure that reflects the on-peak and off-peak time periods of Xcel's pilot tariff and an energy rate differential ratio of at least 2:1. Site hosts may opt out of the default arrangement at their discretion to set pricing that reflects other considerations or needs, provided that such prices are reported to the utility for purposes of Xcel's annual reporting. In its next rate case, Xcel must develop and propose a revised general service TOD rate that is more reflective of hourly system costs with a price signal designed to reduce peak demand. These requirements are consistent with the Commission's directive in the General EV Docket.

2. TOD Rate Design

a. Positions of the Parties

Some parties recommended that the Commission require Xcel to implement a more sophisticated rate design in lieu of the proposed off-peak period of between 9:00 p.m. and 9:00 a.m., which is applicable to participants in both pilots.

The Department had reservations about the 2:1 rate design, stating that without effective price signals to induce charging during off-peak periods, subsidization of EV infrastructure is not fully compatible with the public interest. The Department emphasized the importance of establishing effective price signals at the outset of these pilots to facilitate the success in meeting pilot objectives.

The OAG opposed Xcel's proposed TOD rate structure, arguing that a better rate design would send more accurate price signals by setting rates using an on-peak, a mid-peak, and an-off peak period, similar to Xcel's newly established residential TOD Rate Design Pilot program, which is applicable to residential general service customers, unless those customers opt out of the program.[13]

CUB emphasized that support for transportation electrification is predicated on related system benefits and corresponding savings. CUB echoed the comments of the Department and OAG, stating that a pricing system with critical peak pricing, super off-peak pricing, or real-time pricing would be more effective.

Xcel maintained that its proposed rate structure is reasonable, stating that there is no cost basis to apply the residential TOD rate design to a class of customers with distinct load characteristics. The commercial TOD rates include a demand charge, whereas the residential TOD rates do not. This is an important distinction that encourages efficient use of resources. Further, Xcel stated that the impact of the demand charge is balanced by the provision that limits the billed quantity of peak demand to the amount of kWh energy used in a month, divided by 100 hours.

b. Commission Action

Notably, Xcel's TOD rate proposal was designed with commercial customers in mind. Requiring the Company to implement a three-tiered rate structure similar to what the Commission approved in Xcel's residential TOD Rate Design Pilot program would be premature. That pilot program is ongoing and will study that rate structure's effectiveness within two communities in the Twin Cities metropolitan area.

Recognizing, however, that the Company's proposed rate design with a twelve-hour on- and off-peak period, as applied to commercial customers, is reasonable but is perhaps not optimal for public EV charging, the Commission will require Xcel to file, within six months, a commercial EV charging tariff that is more reflective of hourly system costs with price signals to reduce peak demand. More generally, in its next rate case, Xcel must develop and propose a revised general

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[13] *In the Matter of Xcel's Residential Time of Use Rate Design Pilot Program*, Docket No. E-002/M-17-775, Order Approving Pilot Program, Setting Reporting Requirements, and Denying Certification Request (August 7, 2018).

service TOD rate that is more reflective of hourly system costs with price signals designed to reduce peak demand. These requirements are consistent with the Commission's directive in the General EV Docket.

VI. Smart Charging Capabilities of Charging Equipment

A. The Issue

Xcel has committed to using smart charging equipment for chargers the Company would install at the request of participants in the Fleet EV Service pilot. Xcel's petition does not, however, require all pilot participants to install smart-charging equipment with their chargers. A number of parties recommended that the Commission establish such a requirement.

Smart charging uses technology that is capable of sending data to Xcel to enable more effective load management. In some form, Xcel would have remote capabilities to incentivize charging during off-peak hours, to reduce the coincidence between EV charging and system peak, and to avoid charging during emergencies or other high-peak times.

The Department, Greenlots, ChargePoint, the Clean Energy Organizations, Seimens, and the City of Minneapolis supported requiring smart charging capabilities of all pilot participants. They stated that requiring smart charging capabilities is fundamentally reasonable because even if the Company does not currently have plans to use the technology, it is important to have the capability for future use by ensuring that participants install it at the outset. This, in turn, helps the programs achieve the potential benefits of EVs.

Tesla opposed requiring participants to install smart charging capabilities, stating that it is not clear that the technology will be put to use and that imposing unnecessary requirements does not facilitate pilot participation and is inefficient. Tesla also claimed that such requirements can have unintended consequences to market participants by creating an advantage for some, such as charging stations with certain technology. Instead, Tesla recommended that the issue, along with other standards for interoperability, be evaluated as part of the pilot programs.

Xcel stated that while the Company did not propose a smart-charging requirement as recommended by some parties herein, the Company did not object to doing so, noting that the Company intends to install chargers with such capabilities in its Fleet EV Service pilot to any participants who request that Xcel provide the chargers.

B. Commission Action

The Commission concurs on the reasonableness of requiring pilot participants to install chargers with smart charging capabilities. Remote load management and maintenance is aimed at achieving efficient grid utilization, ultimately benefitting ratepayers. The Commission will therefore require that all chargers installed as part of the pilots have smart charging capabilities.

VII. Deferred Accounting Request

Xcel's petition included a request for deferred accounting of O&M expenses and depreciation expenses related to capital investments in the pilots. Xcel stated that it intends to include these costs for recovery in the Company's next general rate case and requested authorization to track the costs in the EV tracker account established in a separate docket.[14]

A. Introduction

Deferred accounting is a regulatory tool used primarily to hold utilities harmless when they incur out-of-test-year expenses that, because they are unforeseen, unusual, and large enough to have a significant impact on the utility's financial condition, should be eligible for possible rate recovery in the next rate case. Deferred accounting has also been permitted when utilities have incurred sizeable expenses to meet important public policy mandates.

Under Minn. R. 7825.0300, subp. 4, the Commission retains the authority to approve a public utility's request for an exception to a provision of the applicable uniform system of accounts for good cause shown. Xcel has petitioned the Commission for an exception to the standard accounting treatment of certain costs that would otherwise be ineligible for cost recovery because they are incurred between rate cases.

B. Positions of the Parties

Parties disagreed about Xcel's request for deferred accounting. Their positions are discussed below.

1. Comments in Support of the Request

The Alliance for Transportation Electrification supported Xcel's request, stating that deferred accounting provides necessary regulatory certainty in an emerging technology area. Because these proposals will further state goals for emissions reductions and will spur innovation in the transportation sector, the Alliance recommended that the Commission approve the request.

ChargePoint emphasized the strong public policy mandate that the proposals are aimed at fulfilling; the pilots reflect emerging trends and opportunities in electrification of the transportation sector. ChargePoint also stated that the costs were unforeseen at the time of the Company's last general rate case and that it was reasonable for Xcel to pursue the proposals, in spite of the lack of assurance that the associated costs would be eligible for recovery. As a result, ChargePoint recommended that the Commission grant Xcel's request.

2. Comments in Opposition to the Request

The Department, the OAG, and XLI opposed the Company's deferred accounting request.

The Department claimed that costs for equipment beyond the service connection are not suitable for recovery because doing so would potentially stifle competition by giving Xcel an upper hand in the marketplace. The Department also emphasized that Xcel would have the opportunity to recover costs for capital investments in the Company's next rate case after demonstrating that the investments are used and useful in rendering service to customers. Further, the Department stated that these pilots are expected to increase volumetric sales, negating the need for cost recovery and that the Company bears the responsibility to manage its costs between rate cases.

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[14] Xcel's tracker account was established in Docket No. E-002/M-15-111.

The OAG argued that the costs for which Xcel seeks deferred accounting are not significantly sizeable, as they are approximately one-quarter of one percent of the Company's total revenue for the time period of the pilot programs. The OAG also stated that the costs are not associated with important policy mandates because the Commission has not mandated the pilot programs. Finally, the OAG stated that the costs are not unforeseen, unusual, or extraordinary because they relate to the addition of new customers and new load, which are to be expected.

XLI echoed these comments, stating that there is no justification for deferred accounting. XLI stated that granting the request would allow Xcel to avoid scrutiny of its expenditures and that the Company could have planned for such investments in its last rate case. XLI dismissed Xcel's contention that without deferred accounting the Company would not likely pursue such initiatives, claiming that private businesses would be more likely to invest in developing EV-related infrastructure in a competitive environment that excluded a regulated public utility.

3. Xcel's Response

Xcel took issue with characterizations that its request is over-reaching. Xcel stated that deferred accounting is a critical tool affecting the Company's decisions to take on innovative projects between rate cases. Xcel also stated that the Commission has granted deferred accounting requests when important public policy issues are involved.

C. Commission Action

After careful consideration of the record, the Commission will approve Xcel's request for deferred accounting under Minn. R. 7825.0300, subp. 4 for the following reasons.

First, investments for which deferred accounting is sought in this case are clearly intended to serve important public policy objectives. Both the Legislature and the Commission have indicated that transportation electrification is an important public policy goal. The Legislature highlighted this objective by enacting Minn. Stat. § 216B.1614. The Commission has further encouraged utilities in this effort by applying its expertise to direct them to file such proposals, and Xcel's proposed pilots move deliberately and promptly in this direction. The record demonstrates that these two pilots are targeted to explore the potential public benefits of EV adoption and have the potential to be transformative. Supporting the growth of two markets – one for EV public charging stations and the other for Fleet EVs – has the potential to broadly expand access to environmentally beneficial transportation, including to lower-income communities through use of public transit EVs. The Commission's decisions to limit portions of the Fleet EV Pilot to public entities further targets the potential public benefits of the program.

Furthermore, these two pilots will be the first window into evaluating the utility's growing role in transportation electrification—through infrastructure investments in public charging and Fleet EVs and the potential ratepayer benefits derived from that role—the results of which will ultimately guide the Commission's future decisions on other EV programs. Ultimately, they are targeted to produce maximum public and ratepayer benefit, while having a limited rate impact.

Second, the request for deferred accounting in this instance is confined to two proposed pilot programs, both of which are limited in scope and duration. As a result, the potential ratepayer impact of deferred accounting here is constrained by the fact the costs are associated with pilots and not more typical utility investments.

Third, the Commission will further limit the potential cost to ratepayers by restricting the timeframe during which these which these costs will qualify for deferred accounting. Specifically, deferred accounting will apply to costs incurred only after the date of this order up to January 1, 2020, which would be the beginning of the test year for Xcel's next anticipated rate case filing. This protects ratepayers by limiting the total amount of expenses eligible for cost recovery.

Finally and importantly, allowing some costs to qualify for deferred accounting does not guarantee the recovery of those costs. To the contrary, any subsequent request to recover those costs will be separately scrutinized and considered by the Commission in the Company's next general rate case. They will not be recoverable unless shown by the utility to be reasonable and prudent.

For these reasons, the Commission will grant Xcel's request for deferred accounting without requiring the Company to demonstrate that the costs are unforeseen, unusual, and significant in size. This decision is based upon the specific facts of this case, and the Commission will continue to evaluate deferred accounting requests on their own merits in the future.

The Commission will therefore authorize Xcel to defer O&M and depreciation pilot expenses, associated with capital assets placed in service for each pilot, incurred during the period between the date of this order and January 1, 2020, the expected onset of the test year in Xcel's anticipated rate case.

Further, the Commission recognizes that there is a particular need to develop a more comprehensive strategy for encouraging utilities to innovate within the regulatory structure. For that reason, the Commission will require Xcel to address in its next rate case filing how it intends to handle and budget for future pilots prior to its following rate case filing.

VIII. Reporting Requirements

Numerous parties recommended additional reporting requirements beyond those proposed by Xcel. Xcel agreed to include most of them, with the exception of three items.

First, CUB requested that Xcel report on whether third-party development and delivery of charging services provides the highest level of customer benefit compared to other possible delivery methods, such as public, or utility ownership. Xcel stated that because the Company is not proposing ownership of charging stations, the data would not be available.

Second, ILSR recommended that Xcel collect and report data on the cost reductions of participants with Fleet EVs. Xcel stated that the Company is disinclined to ask participants to report on their costs and corresponding costs savings.

Third, ChargePoint recommended that Xcel report data on avoided costs as a result of using smart-charging equipment. Xcel stated that the pilots are not focused on the effectiveness of smart-charging technology and that the request goes beyond the scope of these pilots.

The Commission will incorporate parties' recommended reporting requirements, with the exception of the three recommended items listed above. The Commission concurs with Xcel's reasoning for not including them.

The Commission will establish reporting requirements, as set forth in the ordering paragraphs below. The information required must be filed on an annual basis throughout the pilot as part of Xcel's Annual EV Report in Docket 15-111, with a copy filed in this docket.

IX. Other Commission Action

The Commission will require Xcel to take other action and make filings consistent with the decisions herein, as follows.

Xcel must track both the costs and the associated revenues for each pilot.

Xcel must establish a new tracker account for non-promotional and non-educational expenses associated with each pilot.

In its annual report, Xcel must discuss the interoperability of installed charging equipment under both pilots, including which, if any, standards the pilots require. This should include hardware and software standards.

Within 10 days, Xcel must file its Fleet EV Service pilot agreement for Commission approval. The Commission will delegate authority to the Executive Secretary to approve, via notice, the contract if no interested parties or Commission staff object or file an intent to object within 30 days of the filing.

Within 10 days, Xcel must file its Public Charging pilot agreement for Commission approval. The Commission will delegate authority to the Executive Secretary to approve, via notice, the contract if no interested parties or Commission staff object or file an intent to object within 30 days of the filing.

Where not otherwise noted, Xcel must file a compliance filing consistent with the Commission's decisions in this matter no later than 10 days from the date of this order.

ORDER

1. The Commission hereby approves Xcel's proposal for implementing a Fleet EV Service Pilot and associated tariff, as modified.

2. Within 10 days, Xcel must file its Fleet EV Service Pilot service agreement for Commission approval. The Commission hereby delegates authority to the Executive Secretary to approve, via notice, the contract if no interested parties or Commission staff object or file an intent to object within 30 days of the filing.

3. The Commission hereby approves Xcel's proposal for implementing a Public Charging Pilot and the associated tariff, as modified.

4. Within 10 days, Xcel must file its Public Charging Pilot service agreement for Commission approval. The Commission hereby delegates authority to the Executive Secretary to approve, via notice, the contract if no interested parties or Commission staff object or file an intent to object within 30 days of the filing.

5. Within six months, Xcel must file a commercial EV charging tariff that is more reflective of hourly system costs with a price signal designed to reduce peak demand.

6. The Commission hereby modifies the Public Charging tariff to condition participation in the pilot program on agreement by site hosts to have a default time-differentiated rate structure that reflects the on-peak and off-peak time periods of Xcel's Pilot tariff and an energy rate differential ratio of at least 2:1. However, site hosts may opt out of the default arrangement at their discretion to set pricing that reflects other considerations or needs, provided that such prices are reported to the utility for purposes of Xcel's annual reporting.

7. In its next rate case, Xcel must develop and propose a revised general service TOD rate that is more reflective of hourly system costs with a price signal designed to reduce peak demand.

8. Xcel must ensure that all chargers installed as part of the pilots have smart charging capabilities.

9. Xcel must consider geographic and customer diversity in its selection of additional participants in the Fleet EV Service Pilot. Of the additional participants, one must be a public entity with a primary location outside Ramsey and Hennepin Counties. Further, no more than one of the additional participants in the Fleet EV Service Pilot may be a private or non-profit entity.

10. The Commission hereby approves Xcel Energy's request to classify its make-ready EV infrastructure investments as utility distribution plant for both pilots, as well as Xcel's request to own charging equipment provided under the bundled service option in the Fleet EV Service Pilot. This classification is limited to EV infrastructure investments and charging equipment installed during the pilots.

11. The Commission hereby approves a waiver of service policy provisions for contributions in aid of construction and other customer contributions for only the three-year term of the pilots.

12. Xcel must use its current CIAC formula to determine the amount of subsidy a participant would receive and must track these costs, as well as revenues, for each pilot.

13. The Commission hereby grants deferred accounting for Xcel's O&M and depreciation pilot expenses, associated with capital assets placed in service for each pilot, incurred during the period between issuance of the Commission's order approving the pilots and January 1, 2020, the expected onset of the test year in Xcel's forthcoming rate case.

14. In its next general rate case filing, Xcel must address how it intends to handle and budget for future pilots.

15. Xcel must track both the costs and the associated revenues for each pilot.

16. Xcel must establish a new tracker account for non-promotional and non-educational expenses associated with each pilot.

17. The Commission adopts the following reporting requirements, filed on an annual basis throughout the pilot, as part for Xcel's Annual EV Report in Docket 15-111, with a copy filed in the present docket, 18-643.

18. For the Fleet EV Service Pilot, Xcel must report on:

A. Program level:

1. Participation over time on:
    - a. the number of fleets;
    - b. the number of vehicles; and
    - c. the number of ports
2. End-user satisfaction, including surveys of fleet EV drivers and transit users riding electric buses;
3. Publicly accessible information on site host characteristics; and
4. Customer charging behavior in response to rate structure.

B. Site level, annual:

1. Location of the fleet charging site;
2. Number of ports at the site, and individual port capacities;
3. Costs:
    - a. program implementation;
    - b. installation costs:
        - i. EV service connection;
        - ii. EV supply infrastructure;
        - iii. Optional EV charging equipment;
        - iv. Cost of distribution system upgrade investments for the make-ready component of the pilot, including cost per kW.
    - c. customer service and technical assistance needs;
    - d. dollar estimate of public and private funds being leveraged; and
    - e. any other costs not reflected in the list above.
4. Revenues, broken down by:
    - a. energy revenues;
    - b. demand charge revenues;
    - c. fixed costs revenues; and
    - d. optional charger cost revenues.
5. Whether the customer elected to charge with renewable energy.

C. Site level, monthly:

1. kWh consumed in the on- and off-peak periods of Xcel's tariff;
2. Coincident peak demand, at the MISO system peak and NSP system peak, including the time of day at which the peak occurred;
3. Non-coincident peak demand, including the time of day the peak occurred;
4. Number of vehicles, reported by the customer, using the charging infrastructure; and

5. Percentage of charging that aligned with any onsite generation, if applicable.

19. For the Public Charging Pilot, Xcel must report on:

A. Program level:

1. Participation over time:
   a. number of site hosts;
   b. number of ports;
2. End-user satisfaction;
3. Publically accessible information on site host characteristics; and
4. Customer charging behavior in response to rate structure.

B. Site level, annual:

1. Location of the site;
2. Number of ports at the site, and individual port capacities;
3. Costs:
   a. program installation;
   b. installation costs:
      i. EV service connection
      ii. EV supply infrastructure
      iii. EV charging equipment
      iv. Cost of distribution system upgrade investments for the make-ready component of the pilot, including cost per kW
   c. Customer service and technical assistance needs;
   d. Dollar estimate of public and private funds being leveraged; and
   e. Any other costs not reflected in the list above.
4. Revenues, broken down by:
   a. energy revenues;
   b. demand charge revenues; and
   c. fixed cost revenues.
5. Whether the site host has elected to charge with renewable energy; and
6. Rates and fees charged to end-user customers, and if those rates changed during the year, what period they were in effect.

C. Site level, monthly:

1. kWh consumed in the on-and off-peak periods of Xcel's tariff;
2. Coincident peak demand, at the MISO system peak and NSP system peak, including the time of day at which the peak occurred;
3. Non-coincident peak demand, including the time of day the peak occurred;
4. Number of charging events, times, and durations, to the extent available; and
5. Percentage of charging that aligned with any onsite generation, if applicable.

20. In its annual report, Xcel must discuss the interoperability of installed charging equipment under both pilots, including which, if any, standards the pilots require. This should include hardware and software standards.

21. Where not otherwise noted, Xcel must file a compliance filing consistent with the Commission's decisions in this matter no later than 10 days from the date of this order.

22. This order shall become effective immediately.

BY ORDER OF THE COMMISSION

Daniel P. Wolf
Executive Secretary

This document can be made available in alternative formats (e.g., large print or audio) by calling 651.296.0406 (voice). Persons with hearing loss or speech disabilities may call us through their preferred Telecommunications Relay Service or email consumer.puc@state.mn.us for assistance.

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-20134

At the January 9, 2019 meeting of the Michigan Public Service Commission in Lansing, Michigan.

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

ORDER APPROVING SETTLEMENT AGREEMENT

On May 14, 2018, Consumers Energy Company (Consumers) filed an application seeking authority to increase rates for the generation and distribution of electricity and requesting other regulatory approvals. Consumers indicated in its filing that it projected a $58 million jurisdictional revenue deficiency based on a calendar 2019 test year, which the utility later revised to a $44 million jurisdictional revenue deficiency.

Administrative Law Judge Sharon L. Feldman held a prehearing conference on June 1, 2018, where she granted petitions to intervene filed by the Michigan Department of the Attorney General (Attorney General); the Association of Businesses Advocating Tariff Equity; the Michigan Environmental Council; the Natural Resource Defense Council; Sierra Club; the Kroger Company; Hemlock Semiconductor Operations LLC; the Michigan Cable Telecommunications Association; Energy Michigan, Inc.; the Michigan Energy Innovation Business Council; the Michigan State

Utility Workers Council; ChargePoint, Inc.; the Residential Customer Group (RCG); Wal-Mart Stores East, LP and Sam's East, Inc. (Wal-Mart); the Environmental Law & Policy Center; the Ecology Center; and Midland Cogeneration Venture Limited Partnership (MCV). The Commission Staff (Staff) also participated. Late petitions to intervene were filed by the City of Flint and the City of Grand Rapids, and were granted.

Evidentiary hearings were held on October 11-12 and 15-18, 2018. Briefing took place thereafter. The record in this case consists of 3,630 pages of transcript and 417 exhibits admitted into evidence.

On December 18, 2018, the parties, with the exception of MCV and RCG, filed an executed settlement agreement; and Wal-Mart and the Attorney General filed their non-objections to the settlement agreement that day as well. On December 19, 2018, MCV and RCG filed their non-objections to the settlement agreement, and the Attorney General filed a statement of non-objection to the settlement agreement.

The settlement agreement, attached hereto as Exhibit A, provides for an annual revenue decrease for Consumers of $24 million, simultaneous with termination of the Credit A negative surcharge[1] for electric customers, resulting in an annual revenue increase of approximately $99 million for electric customers.[2] The parties agree that rates reflect the 21% FIT rate and that

[1] The Credit A negative surcharge resulted from passage of the Tax Cuts and Jobs Act of 2017. Credit A refers to the refund due to ratepayers going forward as a result of implementation of a 21% federal income tax (FIT) rate for utilities (the rate was previously 35%). February 22, 2018 order in Case No. U-18494. The Commission approved a settlement agreement providing that the Credit A refund to Consumers' ratepayers equated to a $112.7 million reduction to rates. July 24, 2018 order in Case No. U-20102, Exhibit A, ¶ 4. The agreement also provided that the Credit A negative surcharge would remain in place until new rates were set in Consumers' next electric rate case (the instant case). *Id.,* ¶ 3.

[2] The Staff calculated that the Credit A refund equated to a $123.4 million reduction to rates for the test year. 6 Tr 2339; Staff's initial brief, Appendix A.

Consumers will retain the current return on common equity of 10.0%. Consumers agrees that it will not file a new electric general rate case before January 1, 2020. The allocation of the $24 million revenue decrease is set forth in Attachment 1 to the settlement agreement, and rates and tariffs are substantially set forth in Attachment 2.

The parties agree to certain rate design approaches, including updated determinants for streetlighting fixtures as identified by the Cities of Grand Rapids and Flint, and the allocation of demand response costs to firm loads. The parties agree that Consumers will implement a targeted pilot program offering new residential summer on-peak and all-other hours rates no later than June 2019 and all remaining residential customers will be transitioned to these new rates beginning in January 2020, as described in the testimony of Staff witness David Isakson at 6 Tr 2351-2353. The parties agree to the implementation of the Peak Time Rewards and Critical Peak Price programs, and to the transfer of certain customer groups to these programs.

Consumers agrees to spend at least $200 million on its electric distribution reliability capital program and $53 million on its line clearance program in the 2019 test year (the calendar year), and the parties agree that the Commission should authorize Consumers to use deferred accounting for actual spending above certain threshold amounts during 2019 on the distribution new business capital, distribution reactive failures capital, and distribution asset relocation capital programs. Related to this agreement, Consumers will provide a list of distribution projects to the Staff, will provide the Staff with monthly reports on actual spending on distribution reliability, and will hold workgroups on performance-based ratemaking. Consumers affirms that the projected capital spending included in its application filing “is offset by contributions in aid of construction that does not assume any subsidies by the residential class for large customers or other customer classes.” Exhibit A, ¶ 9.

The parties agree to implementation of the PowerMIDrive program as described in Attachment 3 to the settlement agreement, but indicate that they do not agree on the issue of Consumers' request to recover costs of this program through a deferred accounting mechanism. This unresolved issue is addressed by the Commission in a separate order issued today.

The parties further agree to a state reliability mechanism charge and to the amortization of certain assets. They also agree that Consumers shall retain some of the reparations recently paid by CSX Transportation, and that the remainder shall be returned to customers in a timely manner in future power supply cost recovery proceedings. Consumers further agrees to provide a study analyzing the cost to serve standby service customers, and will provide its distribution cost allocation study to interested parties. Consumers agrees to implement shadow billing as described in the testimony of Staff witness Naomi Simpson at 6 Tr 2571-2573.

The parties agree to maintain the existing non-transmitting meter tariff up-front charges, but to reduce the monthly charge to $3.00. The parties also agree that, for purposes of future demand response spending reconciliations, this settlement should be understood to include $18,942,000 of capital spending, and $12,475,000 of operations and maintenance spending on demand response programs for the 2019 test year.

The Commission has reviewed the settlement agreement and finds that the public interest is adequately represented by the parties who entered into the settlement agreement. The Commission further finds that the settlement agreement is in the public interest, represents a fair and reasonable resolution of the proceedings, and should be approved.

THEREFORE, IT IS ORDERED that:

A. The settlement agreement attached as Exhibit A is approved.

B. Beginning January 10, 2019, Consumers Energy Company shall implement tariffs consistent with the settlement agreement, which are substantially contained in Attachment 2 to the settlement agreement. Due to the size of Attachment 2 to the settlement agreement, it is not physically attached to the original order contained in the official docket or paper copies of the order, but is electronically appended to this order, which is available on the Commission's website.

C. Within 30 days of the date of this order, Consumers Energy Company shall file tariff sheets substantially similar to those contained in Attachment 2 to the settlement agreement.

The Commission reserves jurisdiction and may issue further orders as necessary.

Any party desiring to appeal this order must do so in the appropriate court within 30 days after issuance and notice of this order under MCL 462.26. To comply with the Michigan Rules of Court's requirement to notify the Commission of an appeal, appellants shall send required notices to both the Commission's Executive Secretary and to the Commission's Legal Counsel. Electronic notifications should be sent to the Executive Secretary at mpscedockets@michigan.gov and to the Michigan Department of the Attorney General - Public Service Division at pungp1@michigan.gov. In lieu of electronic submissions, paper copies of such notifications may be sent to the Executive Secretary and the Attorney General - Public Service Division at 7109 W. Saginaw Hwy., Lansing, MI 48917.

MICHIGAN PUBLIC SERVICE COMMISSION

Sally A. Talberg, Chairman

Norman J. Saari, Commissioner

By its action of January 9, 2019.

Kavita Kale, Executive Secretary

EXHIBIT A

S T A T E O F M I C H I G A N

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-20134

SETTLEMENT AGREEMENT

Pursuant to MCL 24.278 and Rule 431 of the Michigan Administrative Hearing System's Rules of Practice and Procedure before the Michigan Public Service Commission ("MPSC" or the "Commission"), the undersigned parties agree as follows:

WHEREAS, on May 14, 2018 Consumers Energy Company ("Consumers Energy" or the "Company") filed an Application requesting authority to increase its rates for the generation and distribution of electricity and other relief. The Company filed testimony and exhibits in support of its positions concurrently with its Application.

WHEREAS, the initial prehearing conference in this proceeding was held on June 1, 2018 before Administrative Law Judge Sharon L. Feldman. The parties to the case are Consumers Energy; the Commission Staff ("Staff"); Attorney General Bill Schuette ("Attorney General"); the Association of Businesses Advocating Tariff Equity ("ABATE"); the Michigan Environmental Council, the Natural Resource Defense Council, and the Sierra Club (collectively "MEC/NRDC/SC"); the Kroger Company ("Kroger"); Hemlock Semiconductor Operations LLC ("HSC"); the Michigan Cable Telecommunications Association ("MCTA"); Energy Michigan, Inc. ("Energy Michigan"); the Michigan Energy Innovation Business Council ("MEIBC"); the Michigan State Utility Workers Council; ChargePoint, Inc.; the Residential Customer Group

(“RCG”); Wal-Mart Stores East, LP and Sam’s East, Inc. (“Walmart”); the Environmental Law & Policy Center and the Ecology Center (collectively, “ELPC”); the City of Flint; the City of Grand Rapids; and Midland Cogeneration Venture Limited Partnership (“MCV”).

WHEREAS, Consumers Energy filed testimony and exhibits requesting an increase in its retail electric rates of $58 million (jurisdictional) and seeking various other forms of relief, and subsequently filed supplemental testimony and exhibits reducing its requested annual increase to $44 million (jurisdictional). Staff and other intervening parties filed testimony and exhibits addressing various issues.

NOW THEREFORE, for purposes of settlement of Case No. U-20134, the undersigned parties agree as follows:

1. Consumers Energy should be authorized to adjust its retail electric base rates so as to produce an annual revenue decrease of $24 million. Simultaneous with the implementation of these reduced rates, the Company will terminate its electric Credit A negative surcharge established in the Commission’s July 24, 2018 Order Approving Settlement Agreement in Case No. U-20102.

2. The parties agree that the annual revenue decrease of $24 million stated in paragraph 1 reflects rates based on a 21% income tax rate as established in the Tax Cuts and Jobs Act of 2017 and further reflects, on a non-precedential basis, an authorized rate of return on common equity of 10.0%.

3. Consumers Energy agrees that it will not file a new electric general rate case under section 6a(1) of Public Act 3 of 1939 as amended, MCL 460.6a(1), earlier than January 1, 2020. Nothing in this Settlement Agreement shall be construed to limit the Company’s right to

file, or the Commission's authority to approve, requests for rate adjustments pursuant to other provisions of law before January 1, 2020.

4. The allocation of the annual revenue requirement decrease of $24 million among the various rate classes that has been agreed upon by the parties is shown on Attachment 1 to this Settlement Agreement. Staff and the Company have determined that the rates and tariffs set forth on Attachment 2 to this Settlement Agreement are cost-based and have been designed to be consistent with the allocations by the Residential, Secondary, Primary and Streetlighting, and Other rate classes to produce an annual revenue decrease of $24 million and reflect the tariff changes agreed to by the parties, and should be approved by the Commission.

5. The parties agree that the annual revenue decrease of $24 million stated in paragraph 1 and the rates identified in Attachment 2 reflect, on a non-precedential basis, the following cost of service and rate design approaches: (i) the use of the "4 CP 75-0-25" cost of service allocation method for production costs; (ii) a load study using class demands based on a three year average of 2015, 2016, and 2017; (iii) updated determinants for Streetlighting fixtures as identified by the Cities of Grand Rapids and Flint and agreed to by Consumers Energy; (iv) updated the Weighted Customer Allocator to reflect the fully deployed costs of smart meters; (v) updated system loss factors as proposed by Consumers Energy; and (vi) the allocation of Demand Response costs to firm loads. The parties agree that the resolution of these and all other issues reflected in this settlement is non-precedential and all parties reserve the right to take different positions in future rate proceedings regarding all such issues.

6. The parties agree that the Commission's directive in its March 29, 2018 Order in Case No. U-18322, which requires the Company to eliminate its current residential summer "inverted block" rate and implement new residential summer on-peak and all-other hours rates

no later than the conclusion of the Company's next rate case (i.e., the instant case), should be modified to adopt a new implementation timeline. The parties agree that the Company should be required to implement a targeted pilot program offering the new residential summer on-peak and all-other hours rates no later than June 2019 as set forth on pages 6 through 8 of the direct testimony of Staff witness David Isakson in this case. All remaining residential customers should be transitioned to the new summer on-peak and all-other hours rates beginning in January 2020 as set forth on pages 6 through 8 of the direct testimony of Staff witness David Isakson in this case.

7. The parties agree that the Commission should approve the Company's proposed Peak Time Rewards ("PTR") and Staff's proposed Critical Peak Price ("CPP") Demand Response provisions for residential customers on an opt-in basis for all customers. The Company will transition its current RDP and RDPR customers to the summer on-peak PTR or CPP. The Company will also transition current REV and RT customers to its Residential Smart Hours and Residential Nighttime Savers rates. Implementation of the PTR and CPP opt-in provision for all residential customers, the transition of the current RDP and RDPR customers, and the transition of the current REV and RT customers will occur following completion of the transition to the summer on-peak rate and modification and testing of Company billing and accounting systems necessary to accommodate these changes.

8. Consumers Energy agrees that it will spend a minimum of $200 million in its electric distribution reliability capital program and $53 million for its line clearing (i.e., tree trimming) Operating and Maintenance ("O&M") program during the 2019 test year in this case. The parties agree that the Commission should authorize Consumers Energy to utilize deferred

accounting associated with actual capital spending above the threshold amounts indicated below during the 2019 test year in this case:

- $94 million in the Company's distribution new business capital program;
- $87 million in the Company's distribution reactive demand failures capital program; and
- $24 million in the Company's distribution asset relocation capital program.

The deferred accounting authorized pursuant to this paragraph will be limited to the return on, return of, and property taxes associated with the actual capital spending above the threshold amounts (including carrying costs). The spending above the threshold amounts will be recorded in a regulatory asset until the associated capital assets are included in rate base in the Company's next electric rate case. In connection with the spending commitments made in this paragraph, Consumers Energy also agrees to the following:

a. Within one month of the Commission's Order approving this Settlement Agreement, Consumers Energy will provide a list of distribution projects to Staff, and other interested parties to this case who have, prior to receipt of the list, signed a non-disclosure certificate pursuant to the protective order entered in this case on June 18, 2018, reflecting the planned reliability work during the 2019 test year. After the end of the 2019 test year, Consumers Energy will provide Staff and other interested parties to this case who have, prior to receipt of the report, signed a non-disclosure certificate pursuant to the protective order entered in this case on June 18, 2018 with a report on actual distribution projects performed and include a comparison to the planned work;

b. Consumers Energy will provide Staff with monthly reports on actual spending in its distribution reliability, new business, reactive demand failures, and asset relocation capital programs as well as its line clearing O&M program. In these reports, the Company will indicate whether spending in each program is projected to exceed the threshold amounts listed above, triggering the need for deferred accounting treatment. Consumers Energy will file these reports in the Commission's electronic docket for Case No. U-20134 on a quarterly basis, no later than one week after CMS Energy's quarterly/annual earnings filings with the SEC (10-Q/10-K); and

c. For purposes of discussion, Consumers Energy will hold workgroup sessions with interested stakeholders on performance-based ratemaking ("PBR"). These workgroup sessions will include discussion on future proposed PBR mechanisms for distribution spending, potentially to include but not be limited to an Investment

> Recovery Mechanism ("IRM"), scope and structure of PBR mechanism(s), performance metrics, performance incentives and penalties, and potential approaches (e.g., a voluntary earnings sharing mechanism) to address unanticipated changes while the IRM or other PBR mechanism(s) is in effect.

9. Consumers Energy asserts and affirms that the projected capital spending included in the Company's filing in this case, including the spending identified in paragraph 8 above, is offset by contributions in aid of construction that does not assume any subsidies by the residential class for large customers or other customer classes.

10. The parties agree that the Commission should adopt the PowerMIDrive pilot program proposed by Consumes Energy in this case, with the modifications adopted by the Company in its rebuttal testimony in this case and the further modifications proposed by Staff in its Initial Brief in this case. Further details of the parties' agreement regarding the design and implementation of the PowerMIDrive pilot program are set forth in Attachment 3 to this Settlement Agreement and are incorporated into this Settlement Agreement as if fully set forth herein. This Settlement Agreement does not resolve the issue of Consumers Energy's request to recover its costs related to the electric vehicle program through a deferred accounting mechanism that allows the Company to earn a return on the costs until they are recovered in a subsequent rate case. The parties request the Commission to address this issue based upon the Initial and Reply Briefs filed pursuant to the schedule established by the Administrative Law Judge in this case.

11. The Company agrees that it will not incur the $2.791 million of capital spending in 2019 that was identified in the Company's filing in this case as "avoidable" under a 2023 retirement scenario for D.E. Karn Units 1 and 2 before a Commission decision in the Company's Integrated Resource Plan case, Case No. U-20165.

12. The parties agree that the State Reliability Mechanism charge adopted for purposes of this case should be $335.99/MW-day. The adoption of this charge is not precedential, and the parties retain the right to litigate the State Reliability Mechanism charge in Consumers Energy's next electric general rate case.

13. The parties agree that the Commission should authorize Consumers Energy to amortize the Traverse City Service Center acquisition adjustment recorded in Consumers Energy's general ledger Account 114, *Electric Plant Acquisition Adjustment*, and record the amortization expense in Account 406, *Amortization of Electric Plant Acquisition Adjustment*, using a 15-year amortization period as proposed in the Company's filing in this case. The parties further agree that the Commission should authorize Consumers Energy to accumulate Information Technology project implementation costs for cloud-based solutions in Plant Account 303, *Miscellaneous Intangible Plant*, and to amortize the intangible asset to expense over the expected useful life of the cloud-based solution as proposed in the Company's filing in this case.

14. Consumers Energy agrees that it will not contribute any of its corporate treasury monies to an Internal Revenue Code 501c(4) entity or an Internal Revenue Code 527 entity during the period of time in which the rates established in this Settlement Agreement are in effect.

15. The parties agree that Consumers Energy should be permitted to retain an amount of the reparations paid by CSX Transportation pursuant to the Surface Transportation Board's January 11, 2018 and August 2, 2018 decisions in Docket No. NOR 42142 sufficient to reimburse the Company for its actual legal fees in that case up to a maximum amount of $8 million. The balance of the reparations paid to Consumers Energy by CSX Transportation as a result of the decisions in Docket No. NOR 42142 will be returned to Consumers Energy's

customers in a timely manner through future Power Supply Cost Recovery proceedings. To the extent that Consumers Energy incurs additional legal fees in connection with Docket No. NOR 42142 above the $8 million cap established in this paragraph, the parties agree that Consumers Energy will be permitted to request further cost recovery for those amounts in a subsequent electric general rate case.

16. Consumers Energy agrees that, in its next electric general rate case, the Company will provide a study analyzing the issue of the cost to serve customers who take standby service. The study will focus on customers with behind-the-meter generation capacity that exceeds 550 kw. The study will review both the actual demands that standby customers place on the system as well as the cost of the investments that are in place to provide standby service.

17. Consumers Energy agrees that, in its next electric general rate case, the Company will provide a cost of service study version that separates the RS and RT rate classes, for informational purposes. In addition, Consumers Energy agrees that, in its next electric general rate case, the Company will provide a cost of service study that reflects projected load reductions to each rate class resulting from rate changes and demand response programs.

18. Consumers Energy agrees that it will provide to interested parties the results of its distribution cost allocation study within 30 days after it is final. In addition, the Company agrees to confer with interested parties after the distribution cost allocation study is shared to answer questions about the study and provide the pertinent back up data.

19. Consumers Energy agrees that it will implement shadow billing in accordance with the testimony by Staff witness Simpson and described in Staff's Initial Brief in this proceeding.

20. Consumers Energy agrees to respond to audit requests of Staff related to Streetlighting conversion costs, provided that any requested vendor pricing be protected pursuant to the June 18, 2018 protective order entered in this case. The Cities reserve applicable rights based upon audit findings.

21. The parties agree that the Commission should maintain the existing up-front charges ($69.39 for customers who do not currently have a transmitting meter installed and $123.91 for customers who already have a transmitting meter installed) for Consumers Energy's non-transmitting meter tariff. The parties agree that the Commission should approve Consumers Energy's proposal to reduce the monthly charges under the Company's non-transmitting meter tariff from $9.72 per month to $3.00 per month.

22. In order to facilitate the Company's reconciliation of Demand Response spending for the period covered by the test year in this case, it is necessary to identify the specific amount of Demand Response spending approved by the Commission in this proceeding. The parties therefore agree that the revenue sufficiency agreed upon in paragraph 1 of this Settlement Agreement should be construed to include $18,942,000 of capital spending and $12,475,000 of O&M spending on Demand Response programs for the test year in this case.

23. In its Application, Consumers Energy requested the Commission to approve an IRM to be operative during the 2020 and 2021 calendar years. The parties agree that the IRM shall not be approved as part of this settlement.

24. The parties agree that the tariff sheets included as Attachment 2 to this Settlement Agreement are consistent with the foregoing provisions of this Settlement Agreement, and should be approved by the Commission.

25. Consumers Energy will conduct periodic meetings with representatives of the Cities of Grand Rapids and Flint on a schedule to be determined. The Cities may facilitate the participation of other municipal customers of Consumers if that participation is coordinated through the Michigan Municipal Association for Utility Issues on a unitary basis. The Company will agree to develop a roadmap which will aim to reduce time and cost burdens on municipalities. The Company agrees to continue discussing in good faith options for addressing the Cities' concern regarding municipalities that paid the full cost of LED conversions prior to Case No. U-17990.

26. Consumers Energy asserts and affirms that, for at least the past 10-year period, the Company has not been found liable of a claim of gross negligence in any court of this state or of any other jurisdiction of the United States. The revenue sufficiency agreed upon in paragraph 1 of this Settlement Agreement does not include any amounts resulting from a finding that Consumers Energy was liable for an act of gross negligence. The parties agree that this Settlement Agreement does not establish any precedent regarding the appropriateness of including damage awards related to judgments for negligence or gross negligence as part of its Injuries and Damages expense in this case or in future Consumers Energy rate cases.

27. This settlement is entered into for the sole and express purpose of reaching a compromise among the parties. All offers of settlement and discussions relating to this settlement are, and shall be considered, privileged under MRE 408. If the Commission approves this Settlement Agreement without modification, neither the parties to this Settlement Agreement nor the Commission shall make any reference to, or use, this Settlement Agreement or the order approving it, as a reason, authority, rationale, or example for taking any action or position or making any subsequent decision in any other case or proceeding; provided, however, such

references may be made to enforce or implement the provisions of this Settlement Agreement and the order approving it.

28. This Settlement Agreement is based on the facts and circumstances of this case and is, subject to paragraph 10, intended for the final disposition of Case No. U-20134. So long as the Commission approves this Settlement Agreement without any modification, the parties agree not to appeal, challenge, or otherwise contest the Commission order approving this Settlement Agreement, except with respect to the issue regarding regulatory asset treatment of PowerMIDrive pilot program costs, which are to be determined by the Commission based on the parties' briefing in this case as set forth above in Paragraph 10. Except as otherwise set forth herein, the parties agree and understand that this Settlement Agreement does not limit any party's right to take new and/or different positions on similar issues in other administrative proceedings, or appeals related thereto.

29. This Settlement Agreement is not severable. Each provision of the Settlement Agreement is dependent upon all other provisions of this Settlement Agreement. Failure to comply with any provision of this Settlement Agreement constitutes failure to comply with the entire Settlement Agreement. If the Commission rejects or modifies this Settlement Agreement or any provision of the Settlement Agreement, this Settlement Agreement shall be deemed to be withdrawn, shall not constitute any part of the record in this proceeding or be used for any other purpose, and shall be without prejudice to the pre-negotiation positions of the parties.

30. The parties agree that approval of this Settlement Agreement by the Commission would be reasonable and in the public interest.

31. The parties agree to waive Section 81 of the Administrative Procedures Act of 1969 (MCL 24.281), as it applies to the issues resolved in this Settlement Agreement, if the Commission approves this Settlement Agreement without modification.

WHEREFORE, the undersigned parties respectfully request the Commission to approve this Settlement Agreement on an expeditious basis and to make it effective in accordance with its terms by final order.

MICHIGAN PUBLIC SERVICE COMMISSION STAFF

By: Heather M.S. Durian Date: December 18, 2018

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[1] Environmental Law and Policy Center and Ecology Center only participated in this case on the PowerMIDrive issue and only sign on to that section of the Settlement Agreement. The organizations have no objection to the other sections of the Settlement Agreement.

MICHIGAN ENVIRONMENTAL COUNCIL, THE NATURAL RESOURCES DEFENSE COUNCIL, AND THE SIERRA CLUB

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The following parties do not wish to be signatories to this Settlement Agreement; however they have agreed to sign below only to indicate non-objection to the Settlement Agreement:

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WAL-MART STORES EAST, LP AND SAM'S EAST, INC.

By: ________________________ Date: ____________________

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THE RESIDENTIAL CUSTOMER GROUP

By: ________________________ Date: ____________________

Don L. Keskey, Esq.
Brian W. Coyer, Esq.
Public Law Resource Center PLLC
333 Albert Avenue, Suite 425
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The following parties do not wish to be signatories to this Settlement Agreement; however they have agreed to sign below only to indicate non-objection to the Settlement Agreement:

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By: ________________________ Date: ____________________

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MIDLAND COGENERATION VENTURE LIMITED PARTNERSHIP

By: __________________________ Date: _____________________

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ATTACHMENT 1

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Present and Proposed Revenue by Rate Schedule
Total Revenues

Attachment 1
To Settlement Agreement In Case No. U-20134

Line No.	(a) Description	(b) Total Present Revenue $000	(c) Total Proposed Revenue $000	(d) Total Net Increase/ (Decrease) $000	(e) Total Net Increase/ (Decrease) %
	Bundled Service				
	Residential Class				
1	Residential RS/Summer On Pk	$ 1,895,200	$ 1,873,313	$ (21,887)	(1.2)
2	Residential RT	8,066	8,406	340	4.2
3	Residential REV	1,491	1,550	59	3.9
4	Residential RDP	10,456	11,019	562	5.4
5	Residential RDPR	7,980	8,283	303	3.8
6	Residential Opt Out	18,220	17,977	(243)	(1.3)
7	Total Residential Class	1,941,413	1,920,548	(20,866)	(1.1)
	Secondary Class				
8	Secondary Energy-only GS	572,254	576,818	4,564	0.8
9	Secondary Demand GSD	482,938	463,559	(19,379)	(4.0)
10	Secondary Energy-only GS TOU	-	-	-	NA
11	Total Secondary Class	1,055,193	1,040,377	(14,816)	(1.4)
	Primary Class				
12	Primary Energy-only GP	163,944	168,524	4,580	2.8
13	Primary Demand GPD	871,826	880,832	9,006	1.0
14	Primary Energy Intensive Rate EIP	22,137	22,424	286	1.3
15	Primary Time of Use Pilot GPTU	63,161	63,980	820	1.3
16	Total Primary Class	1,121,069	1,135,760	14,692	1.3
	Lighting & Unmetered Class				
17	Metered Lighting Service GML	1,811	1,717	(94)	(5.2)
18	Unmetered Lighting Service GUL	30,680	32,074	1,394	4.5
19	Unmetered Exp. Lighting GU-XL	1,365	1,396	31	2.2
20	Unmetered Service GU	8,296	8,562	266	3.2
21	Total Lighting & Unmetered Class	42,152	43,749	1,597	3.8
	Self-generation Class				
22	Small Self-generation GSG-1	-	-	-	NA
23	Large Self-generation GSG-2	3,429	1,535	(1,894)	NA
24	Total Self-Generation Class	3,429	1,535	(1,894)	NA
25	Total Bundled Service	$ 4,163,255	$ 4,141,969	$ (21,287)	(0.5)
	ROA Service				
	Residential Class				
26	Residential Service RS	$ -	$ -	$ -	NA
27	Residential Time-of-Day RT	-	-	-	NA
28	Total Residential Class	-	-	-	NA
	Secondary Class				
29	Secondary Energy-only GS	953	946	(7)	(0.7)
	Standard Service	296	294	(2)	(0.7)
	Education GEI	657	652	(5)	(0.8)
30	Secondary Demand GSD	7,948	6,831	(1,117)	(14.1)
	Standard Service	5,411	4,639	(771)	(14.3)
	Education GEI	2,538	2,192	(346)	(13.6)
31	Total Secondary Class	8,902	7,777	(1,124)	(12.6)
	Primary Class				
32	Primary Energy-only GP	1,245	973	(271)	(21.8)
33	Primary Demand GPD	20,486	18,440	(2,046)	(10.0)
34	Total Primary Class	21,730	19,413	(2,317)	(10.7)
35	Total ROA Service	$ 30,632	$ 27,190	$ (3,442)	(11.2)
36	Total Bundled and ROA Service	$ 4,193,887	$ 4,169,159	$ (24,728)	(0.6)

ATTACHMENT 2

INDEX

(Continued From Sheet No. A-4.00)

SECTION D
RATE SCHEDULES (Contd)

(Continued on Sheet No. A-6.00)

(Continued From Sheet No. C-3.00)

C1. CHARACTERISTICS OF SERVICE (Contd)

C1.4 Extraordinary Facility Requirements and Charges (Contd)

Contribution In Aid of Construction Allowance Schedule

Schedule	Customer Voltage Level(CVL)	With a Full Service Contract, by Contract Duration					Without Full Service Contract
		1 Year	2 Year	3 Year	4 Year	5 Year	
General Service Primary Rate GP	1	$~~0.024~~ *0.029*/kWh	$~~0.046~~ *0.056*/kWh	$~~0.066~~ *0.082*/kWh	$~~0.085~~ *0.105*/kWh	$~~0.102~~ *0.127*/kWh	$~~0.023~~ *0.018*/kWh
	2	~~0.031~~ *0.034*/kWh	~~0.051~~ *0.065*/kWh	~~0.074~~ *0.094*/kWh	~~0.095~~ *0.122*/kWh	~~0.115~~ *0.147*/kWh	~~0.031~~ *0.024*/kWh
	3	~~0.049~~ *0.042*/kWh	~~0.065~~ *0.079*/kWh	~~0.094~~ *0.114*/kWh	~~0.121~~ *0.147*/kWh	~~0.146~~ *0.177*/kWh	~~0.049~~ *0.042*/kWh
Large General Service Primary Demand Rate GPD	1	$~~85~~ *125*/kW	$~~165~~ *240*/kW	$~~240~~ *345*/kW	$~~310~~ *450*/kW	$~~375~~ *540*/kW	$40/kW
	2	~~95~~ *150*/kW	~~185~~ *295*/kW	~~270~~ *425*/kW	~~345~~ *545*/kW	~~415~~ *660*/kW	~~70~~ *75*/kW
	3	~~150~~ *185*/kW	~~245~~ *360*/kW	~~355~~ *525*/kW	~~460~~ *675*/kW	~~555~~ *815*/kW	~~150~~ *140*/kW
General Service Primary Time-of-Use Rate GPTU	1	~~0.015~~ *0.022*/kW h	~~0.029~~h *0.042*/kW	~~0.042~~ *0.061*/kWh	~~0.055~~ *0.079*/kWh	~~0.066~~ *0.095*/kW	NA
	2	~~0.017~~ *0.027*/kWh	~~0.032~~ *0.051*/kWh	~~0.047~~ *0.075*/kWh	~~0.061~~ *0.096*/kWh	~~0.073~~ *0.116*/kWh	NA
	3	~~0.022~~ *0.033*/kWh	~~0.043~~ *0.064*/kWh	~~0.062~~ *0.092*/kWh	~~0.080~~ *0.119*/kWh	~~0.097~~ *0.143*/kWh	NA
Energy Intensive Primary Rate EIP	1	~~0.002~~ *0.006*/kWh	~~0.003~~ *0.011*/kWh	~~0.005~~ *0.015*/kWh	~~0.006~~ *0.020*/kWh	~~0.008~~ *0.024*/kWh	NA
	2	~~0.004~~ *0.010*/kWh	~~0.009~~ *0.019*/kWh	~~0.012~~ *0.027*/kWh	~~0.016~~ *0.035*/kWh	~~0.019~~ *0.042*/kWh	NA
	3	~~0.007~~ *0.012*/kWh	~~0.014~~ *0.022*/kWh	~~0.020~~ *0.032*/kWh	~~0.026~~ *0.042*/kWh	~~0.032~~ *0.050*/kWh	NA

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

Contributions in Aid of Construction otherwise required by the Company may be suspended for publicly available AC Level 2 or DC Fast Charge sites participating in the PowerMIDrive pilot. Suspension is at the Company's sole discretion, for a term of three years from the date of Commission approval of the PowerMIDrive pilot.

C1.5 Invalidity of Oral Agreements or Representations

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

(Continued on Sheet No. C-4.00)

(Continued From Sheet No. C-23.00)

C4. APPLICATION OF RATES (Contd)

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

D. Rate Application for Seasonal Condominium Campgrounds (Contd)

(5) The customer must notify individuals and/or co-owners utilizing the customer's property that the customer's facilities may not be able to be located by Miss Dig.
(6) The customer must notify individuals and co-owners utilizing the customer's property that requests and concerns regarding electric service will be addressed between the single legal entity and ownership and primary operating authority, not with individuals.
(7) The customer shall be responsible for ensuring that the electrical facilities are adequate to meet the needs of the units placed within the Seasonal Condominium Campground in their entirety and shall pay the Company for any charges incurred for modifications necessary to accommodate load according to other portions of this Electric Rate Book.

C4.4 Resale

This provision is closed to resale for general unmetered service, unmetered or metered lighting service and new or expanded service for resale for residential use.
No customer shall resell electric service to others except when the customer is served under a Company rate expressly made available for resale purposes, and then only as permitted under such rate and under this rule.

Where, in the Company's opinion, the temporary or transient nature of the proposed ultimate use, physical limitation upon extensions, or other circumstances, make it impractical for the Company to extend or render service directly to the ultimate user, the Company may allow a customer to resell electric service to others.

For the purposes of this tariff, the provision of electric vehicle charging service for which there is no direct per kWh charge shall not be considered resale of service.

A resale customer is required to take service under the resale provision of one of the following rates for which they qualify: General Service Secondary Rate GS, *General Service Secondary Time-of-Use Rate GSTU,* General Service Secondary Demand Rate GSD, General Service Primary Rate GP, ~~or~~ Large General Service Primary Demand Rate GPD*, or General Service Primary Time-of-Use Rate GPTU*. Resale Service is provided pursuant to a service contract providing for such resale privilege. Service to each ultimate user shall be separately metered.

A. If the resale customer elects to take service under a Company Full Service resale rate, the ultimate user shall be served and charged for such service under standard Rate RS for residential use or under the appropriate standard General Service Rate applicable in the Company's Electric Rate Book available for similar service under like conditions. Reselling customers are not required to offer or administer any additional service provisions or nonstandard rates contained in the Electric Rate Book, such as the Income Assistance Service Provision, Residential Service Time-of-Day Secondary Rate RT or the Educational Institution Service Provision.

B. If the resale customer elects to take service under a Company Retail Open Access Service rate, the ultimate user shall be served and charged for such service under Rate ROA-R for residential use or under Rate ROA-S or ROA-P applicable in the Company's Electric Rate Book available for similar service under like conditions.

C. If the ultimate user is a campground lot or boat harbor slip, the resale customer has the option to charge a maximum of the following all-inclusive rate per kWh in place of billing the ultimate customer on the appropriate standard Company tariff rate:

$~~0.151312~~ *0.149825* per kWh for all kWh during the months of June-September
$~~0.147394~~ *0.148848* per kWh for all kWh during the months of October-May

The Company shall be under no obligation to furnish or maintain meters or other facilities for the resale of service by the reselling customer to the ultimate user.
The service contract shall provide that the reselling customer's billings to the ultimate user shall be audited each year by February's month end, for the previous calendar year. The audit shall be conducted either by the Company, if the Company elects to conduct such audit, or by an independent auditing firm approved by the Company. The reselling customer shall be assessed a reasonable fee for an audit conducted by the Company. If the audit is conducted by an independent auditing firm, the customer shall submit a copy of the results of such audit to the Company in a form approved by the Company.

(Continued on Sheet No. C-25.00)

(Continued From Sheet No. C-24.00)

C4. APPLICATION OF RATES (Contd)

C4.4 Resale (Contd)

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

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

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

If the reselling customer fails to meet the obligations of this rule, the Company shall notify the Commission. If, after review with the reselling customer, the problem is not resolved, the Company shall assess a penalty in the amount of ~~5~~*15*% of the resale customer's bill before taxes per month until the problem is resolved. The reselling customer is not permitted to pass the resale penalty cost on to its ultimate customer(s). If the problem is not resolved after three months, the Company shall shut off electric service until the problem is resolved. The Company shall not incur any liability as the result of this shutoff of electric service.

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

Neither the resale of electric services provided by Consumers Energy nor the sale of self-generation at publicly available electric vehicle charging stations is subject to Commission regulation and no restrictions are imposed on the rate charged or rate structure to the ultimate motor vehicle customers, as those sales are being made into the competitive motor fuels market.

C4.5 Mobile Home Park - Individually Served

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

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

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

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

(Continued on Sheet No. C-26.00)

(Continued From Sheet No. C-32.00)

C5. CUSTOMER RESPONSIBILITIES (Contd)

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

B. Enrollment

An eligible customer may enroll at any time of the calendar year in the SPP. Where unauthorized use of utility service has not occurred, to enroll an eligible customer must (1) contact the Company and indicate that they wish to enroll, (2) be able to demonstrate that he or she has made application for state or federal heating assistance, or has a household income that does not exceed 200% of the federal poverty guidelines as published by the United States Department of Health and Human Services or receives supplemental security income or low-income assistance through the Department of Human Services or successor agency, food stamps, or Medicaid, (3) within 14 days of a customer calling to enroll in the SPP, have completed the enrollment process by paying a minimum down payment of 10% of the total amount owed to the Company at the time of the request to enroll. An eligible customer is not enrolled in the SPP until the enrollment requirements are fulfilled. Customers previously enrolled in the SPP the last twelve months who default may be permitted to re-enroll in a modified SPP payment arrangement, at the discretion of the Company, if they have demonstrated a willingness to satisfy the terms of the payment plan through their payment history or have received assistance that will improve the customer's ability to satisfy the payment arrangements. The modified SPP repayment period shall not exceed 24 months.

Customers who enroll in the SPP who have not been enrolled in the SPP for more than twelve months may not be required to pay a deposit or reconnection fee, if applicable. Customers who enroll in the SPP who were previously enrolled in the SPP in the last twelve months and removed due to default may be required to pay a deposit and a reconnection fee, if applicable.

Where unauthorized use of utility service has occurred, the customer must pay 100% of the portion of charges that are the result of the unauthorized use. Upon receipt of payment, the customer shall be considered eligible if all other eligibility requirements are met. The customer may then enroll under the conditions described previously. The payment of unauthorized use charges may be made at the same time as the down payment of the total amount owed to the Company is made. In the event that the down payment of the total amount owed to the Company is made without payment of the unauthorized charges at the same time or previously, the payment received shall first be applied to the unauthorized charges.

In the event that an eligible customer has contacted the Company to indicate a wish to enroll but the requirements so described are not met in full, the eligible customer shall then be subject to credit action as though no contact with the Company had occurred. In the event that all Company obligations to shut off service have been met, the eligible customer shall receive a minimum of one communication at least 24 hours prior to shutoff of service.

C. Customer Protection

Once enrolled in the SPP, a utility shall not shut off service to a SPP Customer if the customer pays to the Company a monthly amount equal to 1/12th of the estimated annual bill for the SPP Customer and a Company-specified amount between 1/12th and 1/24th of any remaining delinquent balance owed to the Company at the time of the enrollment. *The Company shall have the right to deny or shut off service in accordance with Rules and Regulations of the Company as authorized by the Michigan Public Service Commission outlined in Rule C1.3, Use of Service and in Rule C5.1, Access to Customer's Premises.* While the customer is enrolled in the SPP and payments are made by the due date of the amount due shown on the bill, no late payment charges will be assessed. The SPP Customer may participate in the SPP for a maximum period of 24 months or until the delinquent charges are eliminated and the SPP Customer is able to pay his or her regular monthly energy bills.

(Continued on Sheet No. C-32.20)

(Continued From Sheet No. C-32.10)

C5. CUSTOMER RESPONSIBILITIES (Contd)

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

C. Customer Protection (Contd)

The estimated annual bill for the SPP Customer and the delinquent balance due may be recalculated periodically by the Company. The Company may also recalculate the estimated annual bill and the delinquent balance due upon the transfer of a balance owed on another account in compliance with Rule B2., Consumer Standards and Billing Practices for Electric and Natural Gas Service.

D. Default

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

E. Participation in Other Shutoff Protection Plans

Customers eligible to participate under the Winter Protection Plan, Rules R 460.131 and R 460.132, will be required to waive their rights to participate under the Winter Protection Plan in order to participate in the Plan. Upon enrollment, the Company shall send written confirmation of the enrollment terms and include notice of this provision.

C5.5 Non-Transmitting Meter Provision

Customers served on Residential Service Secondary Rates RS and General Service Secondary Rates GS have the option to choose a non-transmitting meter. In order for a customer to be eligible to participate in the Non-Transmitting Meter Provision, the customer must have a meter that is accessible to Company employees and the customer shall have zero instances of unauthorized use, theft, fraud and/or threats of violence toward Company employees.

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

Up Front Charge:	$ 69.39	a one-time charge per billing meter per request if the notice is given before the transmitting meter is installed
	OR	
	$123.91	a one-time charge per billing meter per request if the notice is given after the transmitting meter is installed
Monthly Charge:	$ *5.68* ~~9.72~~	per month at each premises as defined in Rule B1., Technical Standards for Electric Service. Multiple metered units shall be charged per billing meter.

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

(Continued on Sheet No. C-32.30)

(Continued From Sheet No. C-33.00)

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

C6.1 Overhead Extension Policy (Contd)

C. General (Contd)

(6) The Company reserves the right to make special contractual arrangements as to the provision of necessary Service Facilities, duration of contract, amount of deposit and refunds thereon, minimum bills or other service conditions with respect to the customers or prospective customers whose load requirements exceed the capacity of the available distribution system in the area, or whose load characteristics or special service needs require unusual investments by the Company in Service Facilities or where there is not sufficient assurance of the permanence of the use of the service. The Company shall construct overhead electric distribution facilities and extensions only in the event it is able to obtain or use the necessary materials, equipment and supplies. The Company, subject only to review by the Commission, reserves the right, in its discretion, to allocate the use of such materials, equipment and supplies it may have on hand from time to time among the various classes of customers and prospective customers and among various customers and prospective customers of the same class.

(7) Contributions in Aid of Construction otherwise required by the Company may be suspended for publicly available AC Level 2 or DC Fast Charge sites participating in the PowerMIDrive pilot. Suspension is at the Company's sole discretion, for a term of three years from the date of Commission approval of the PowerMIDrive pilot.

(*8*~~7~~) All service rendered shall be subject to the Company's Standard Contract forms and to its Electric Rate Book.

(*9*~~8~~) Any charges, deposits or contributions may be required In Advance of commencement of construction.

C6.2 Underground Policy

A. General

This rule sets forth the conditions under which the Company shall install direct burial underground electric distribution systems and underground service connections for residential and General Service customers. For the purpose of this rule, such underground distribution facilities are defined as those facilities operated at 15,000 Volts or less phase to ground wye connected or 20,000 Volts or less phase to phase delta connected.

The general policy of the Company is that real estate developers, property owners or other applicants for underground service shall make a contribution in aid of construction to the Company in an amount equal to the estimated difference in cost between underground and equivalent overhead facilities.

Methods for determining this cost differential for specific classifications of service are provided herein. In cases, where the nature of service or the construction conditions are such that these conditions are not applicable, the general policy stated above shall apply.

It shall be mandatory that all original electric distribution systems installed in new residential subdivisions and in existing residential subdivisions in which overhead electric distribution facilities have not already been constructed be placed underground, except that a lot within a subdivision facing a previously existing street or county road and having an existing overhead distribution line on its side of the street or county road shall be served with an underground service from these facilities and shall be considered a part of the underground service area. It shall also be mandatory that all original service connections installed to serve one-family or two-family dwellings from an underground distribution system be placed underground.

Except as otherwise provided in the following paragraph, it shall be mandatory that all new General Service distribution systems and service connections installed in the vicinity of or on the customer's premises to be served, and constructed solely to serve the customer or a group of adjacent customers, be placed underground.

(Continued on Sheet No. C-35.00)

(Continued From Sheet No. C-39.00)

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

C6.2 Underground Policy (Contd)

E. Where, in the Company's judgment, practical difficulties exist, such as frost or water conditions, rock near the surface, or where there are requirements for deviation from the Company's filed construction standards, the per foot charges included in this Rule C6.2, Underground Policy, shall not apply and the contribution in aid of construction shall be equal to the estimated difference in cost between overhead and underground facilities but not less than the contribution calculated under the appropriate per foot charge.

F. Where electric facilities are placed underground at the option of the Company for its own convenience, or where underground construction is required by ordinance in heavily congested downtown areas, the Company shall bear the cost of such construction.

G. Conditions

The Company reserves the right to make special contractual arrangements as to the provision of necessary Service Facilities, duration of contract, amount of deposit and refunds thereon, minimum bills or other service conditions with respect to the customers or prospective customers whose load requirements exceed the capacity of the available distribution system in the area, or whose load characteristics or special service needs require unusual investments by the Company in Service Facilities or where there is not sufficient assurance of the permanence of the use of the service. The Company shall construct underground electric distribution facilities and extensions only in the event it is able to obtain or use the necessary materials, equipment and supplies. The Company, subject only to review by the Commission, reserves the right, in its discretion, to allocate the use of such materials, equipment and supplies it may have on hand from time to time among the various classes of customers and prospective customers and among various customers and prospective customers of the same class.

<u>Contributions in Aid of Construction otherwise required by the Company may be suspended for publicly available AC Level 2 or DC Fast Charge sites participating in the PowerMIDrive pilot. Suspension is at the Company's sole discretion, for a term of three years from the date of Commission approval of the PowerMIDrive pilot.</u>

All service rendered shall be subject to the Company's Standard Contract forms and to its Electric Rate Book.

H. Any charges, deposits or contributions may be required In Advance of commencement of construction.

(Continued on Sheet No. C-41.00)

(Continued From Sheet No. C-41.00)

C8. POWER SUPPLY COST RECOVERY (PSCR) CLAUSE (Contd)

A. Applicability of Clause (Contd)

"Power Supply Costs" means those elements of the costs of fuel and purchased and net interchanged power as determined by the Commission to be included in the calculation of the Power Supply Cost Recovery Factor. The Commission determined in its Order in Case No. U-10335 dated May 10, 1994 that the fossil plant emissions permit fees over or under the amount included in base rates charged the Company are an element of fuel costs for the purpose of the clause.

B. Billing

(1) The Power Supply Cost Recovery Factor shall consist of an adjustment factor of ~~1.0805~~ *1.07933* applied to projected average booked cost of fuel burned for electric generation and purchased and net interchange power incurred above or below a cost base of $0.05570 per kWh (excluding line losses). Average booked costs of fuel burned and purchased and net interchange power shall be equal to the booked costs in that period divided by that period's net system kWh requirements. The average booked costs so determined shall be truncated to the full $0.00001 cost per Kilowatt-hour. Net system kWh requirements shall be the sum of the net kWh generation and net kWh purchased and interchange power.

(2) Each month the Company shall include in its rates a Power Supply Cost Recovery Factor up to the maximum authorized by the Commission as shown on Sheet No. D-4.00.

Should the Company apply lesser factors than those shown on Sheet No. D-4.00, or if the factors are later revised pursuant to Commission Orders or Michigan Compiled Laws, Annotated, 460.6 et seq., the Company shall notify the Commission if necessary and file a revised Sheet No. D-4.00.

C. General Conditions

(1) The power supply and cost review shall be conducted not less than once a year for the purpose of evaluating the Power Supply Cost Recovery Plan filed by the Company and to authorize appropriate Power Supply Cost Recovery Factors. Contemporaneously with its Power Supply Cost Recovery Plan, the Company shall file a 5-year forecast of the power supply requirements of its customers, its anticipated sources of supply and projections of Power Supply Costs.

(2) Not more than 45 days following the last day of each billing month in which a Power Supply Cost Recovery Factor has been applied to customers' bills, the Company shall file with the Commission a detailed statement for that month of the revenues recorded pursuant to the Power Supply Cost Recovery Factor and the allowance for cost of power included in the base rates established in the latest Commission order for the Company, and the cost of power supply.

(3) All revenues collected pursuant to the Power Supply Cost Recovery Factors and the allowance for power included in the base rates are subject to annual reconciliation proceedings.

(Continued on Sheet No. C-43.00)

(Continued from Sheet No. C-48.64)

C10. RENEWABLE ENERGY PLAN (REP) (Contd)

C10.5 Pilot Solar Program (Contd)

E. Solar Energy Credits

Solar Energy Credits applied to the customer's monthly bill are based on the customer's subscription level, the energy credit and the capacity credit.

The Solar Energy Credits in years one through five will be based on the Short Term Program Energy and Capacity Value and in years six through twenty-five on the sum of the Long Term Program Energy Value and the Long Term Program Capacity Value.

The Long Term Program Energy Value includes a factor to account for avoided line losses attributable to the distributed resource location on the distribution system. The avoided line loss factor is ~~2.71~~ *2.32*%. This value will be revised when line losses are updated in general electric rate cases, as approved by the Commission.

Customers that chose to have the REC sold when this option was initially available will be credited quarterly. The REC credit is based on a Michigan Renewable Portfolio Standard REC value published quarterly in the Midwest Market Notes by Clear Energy Brokerage and Consulting, LLC, or successor publication, multiplied by the RECs generated. Alternatively, the REC value may be based on the actual sale of the RECs.

If the monthly Solar Energy Credit is greater than the customer's bill, the excess credit will be rolled over and applied to the next month's bill. If a Solar Energy Credit accumulates to an amount greater than $100, the Company shall pay the balance to the customer.

F. Reporting

Solar Program production data will be available on the Company's website. Each participating customer's monthly energy bill will include the Subscription Payment and Solar Energy Credit.

The Company will provide quarterly reports to the MPSC detailing the enrollment status and Solar Program production.

G. Cost Recovery

Costs will be recovered as set forth in the Commission Order in Case No. U-17752.

(Continued on Sheet No. C-48.67)

RATE CATEGORIES AND PROVISIONS

Description	Full Service	Retail Open Access
RESIDENTIAL SUMMER ON-PEAK BASIC RATE RSP		
Residential	*1001*	*Not Applicable*
Provisions		
*Residential Summer On-Peak Basic With Income Assistance (RIA) **	*Applicable*	*Not Applicable*
*Residential Summer On-Peak Basic With Senior Citizen (RSC) **	*Applicable*	*Not Applicable*
Peak Power Savers – Air Conditioner Peak Cycling Program	*Applicable*	*Not Applicable*
Peak Power Savers – Peak Reward	*Applicable*	*Not Applicable*
Peak Power Savers – Critical Peak Pricing	*Applicable*	*Not Applicable*
*Residential Summer On-Peak Basic With Self-Generation (SG)***	*1700*	*Not Applicable*
Net Metering Program	*Applicable*	*Not Applicable*
Green Generation Program	*Applicable*	*Not Applicable*
RESIDENTIAL SERVICE SECONDARY RATE RS		
Residential	1000	2000
Provisions		
Residential With Income Assistance (RIA) *	Applicable	Applicable
Residential With Senior Citizen (RSC) *	Applicable	Applicable
Peak Power Savers – Air Conditioner Peak Cycling Program	1005	Not Applicable
Residential With Self-Generation (SG)**	1700	Not Applicable
Net Metering Program	Applicable	Applicable
Green Generation Program	Applicable	Not Applicable
Non-Transmitting Meter Provision	Applicable	Applicable
RESIDENTIAL SERVICE DYNAMIC PROGRAM		
Peak Power Savers – Critical Peak Time-of-Use (RDP)	1007	Not Applicable
Peak Power Savers – Peak Rewards Time-of-Use (RDPR)	1008	Not Applicable
Provisions		
Residential Dynamic Pricing With Income Assistance (RIA)*	Applicable	*Not* Applicable
Residential Dynamic Pricing With Senior Citizen (RSC)*	Applicable	*Not* Applicable
Residential Dynamic Pricing With Self-Generation (SG)**	1700	Not Applicable
Green Generation Program	Applicable	Not Applicable
RESIDENTIAL SERVICE TIME-OF-DAY SECONDARY RATE RT		
Residential Time-of-Day	1010	2010
Provisions		
Residential Time-of-Day With Income Assistance (RIA) *	Applicable	Applicable
Residential Time-of-Day With Senior Citizen (RSC)*	Applicable	Applicable
Residential Time-of-Day With Self-Generation (SG)**	1705	Not Applicable
Net Metering Program	Applicable	Applicable
Green Generation Program	Applicable	Not Applicable

* Provisions shall not be taken in conjunction with each other.
** Provisions shall not be taken in conjunction with the Net Metering Program.

(Continued on Sheet No. D-~~6.10~~ *6.05*)

Attachment 2
To Settlement Agreement In Case No. U-20134

RATE CATEGORIES AND PROVISIONS

(Continued From Sheet No. D-6.00)

EXPERIMENTAL RESIDENTIAL PLUG-IN ELECTRIC VEHICLE CHARGING PROGRAM

Residential Electric Vehicle Service (REV-1)	1020	Not Applicable
Residential Electric Vehicle Service (REV-1) With Self-Generation (SG)**	1710	Not Applicable
Residential Electric Vehicle Service (REV-2)	1030	Not Applicable
Green Generation Program	Applicable	Not Applicable

RESIDENTIAL SMART HOURS RATE RSH

Residential	*1XXX*	*Not Applicable*
Provisions		
*Residential Smart Hours With Income Assistance (RIA) **	*Applicable*	*Not Applicable*
*Residential Smart Hours With Senior Citizen (RSC) **	*Applicable*	*Not Applicable*
Peak Power Savers – Air Conditioner Peak Cycling Program	*Applicable*	*Not Applicable*
Peak Power Savers – Peak Reward	*Applicable*	*Not Applicable*
Peak Power Savers – Critical Peak Pricing	*Applicable*	*Not Applicable*
*Residential Smart Hours With Self-Generation (SG)***	*1700*	*Not Applicable*
Net Metering Program	*Applicable*	*Not Applicable*
Green Generation Program	*Applicable*	*Not Applicable*

RESIDENTIAL NIGHTTIME SAVERS RATE RPM

Residential	*1XXX*	*Not Applicable*
Provisions		
*Residential Nighttime Savers With Income Assistance (RIA) **	*Applicable*	*Not Applicable*
*Residential Nighttime Savers With Senior Citizen (RSC) **	*Applicable*	*Not Applicable*
Residential Nighttime Savers With Electric Vehicle Only Charging Credit (REV)	*Applicable*	*Not Applicable*
Peak Power Savers – Air Conditioner Peak Cycling Program	*Applicable*	*Not Applicable*
Peak Power Savers – Peak Reward	*Applicable*	*Not Applicable*
Peak Power Savers – Critical Peak Pricing	*Applicable*	*Not Applicable*
*Residential Nighttime Savers With Self-Generation (SG)***	*1700*	*Not Applicable*
Net Metering Program	*Applicable*	*Not Applicable*
Green Generation Program	*Applicable*	*Not Applicable*

* Provisions shall not be taken in conjunction with each other.
** Provisions shall not be taken in conjunction with the Net Metering Program.

(Continued on Sheet No. D-6.10)

RATE CATEGORIES AND PROVISIONS

(Continued From Sheet No. D-~~6.00~~ *6.05*)

Description	Full Service	Retail Open Access
GENERAL SERVICE SECONDARY RATE GS		
Commercial	1100	2100
Commercial - Temporary Construction Service	1999	Not Applicable
Provisions		
Commercial Billboards/Outdoor Advertising Signs - Dusk to Dawn	Applicable	Not Applicable
Commercial Billboards/Outdoor Advertising Signs - Fixed Hours of Operation	Applicable	Not Applicable
Commercial Miscellaneous	Applicable	Not Applicable
Commercial Resale	Applicable	Applicable
Commercial With Educational Institution (GEI)	Applicable	Applicable
Commercial With Self-Generation (SG) *	1715	Not Applicable
Net Metering Program	Applicable	Applicable
Green Generation Program	Applicable	Not Applicable
Non-Transmitting Meter Provision	Applicable	Applicable
GENERAL SERVICE SECONDARY TIME-OF-USE RATE GSTU		
Commercial	1121	Not Applicable
Provisions		
Commercial With Educational Institution (GEI)	Applicable	*Not* Applicable
Commercial With Self-Generation (SG) *	1716	Not Applicable
Commercial Resale	*Applicable*	*Not Applicable*
Green Generation Program	Applicable	Not Applicable
GENERAL SERVICE SECONDARY DEMAND RATE GSD		
Commercial	1120	2120
Commercial (100 kW Billing Demand Guarantee)	1140	2140
Provisions		
Commercial Resale	Applicable	Applicable
Commercial With Educational Institution (GEI)	Applicable	Applicable
Commercial With Self-Generation (SG) *	1725	Not Applicable
Commercial (100 kW Billing Demand Guarantee) With Self-Generation (SG) *	1735	Not Applicable
Net Metering Program	Applicable	Applicable
Green Generation Program	Applicable	Not Applicable

*Provisions shall not be taken in conjunction with the Net Metering Program.

(Continued on Sheet No. D-7.00)

RATE CATEGORIES AND PROVISIONS

(Continued From Sheet No. D-6.10)

Description	Full Service	Retail Open Access
GENERAL SERVICE PRIMARY RATE GP		
Commercial (Customer Voltage Level 1, 2 or 3)	1200	2200
Industrial (Customer Voltage Level 1, 2 or 3)	1210	2210
Provisions		
Commercial (Customer Voltage Level 1, 2 or 3) Resale	Applicable	Applicable
Commercial (Customer Voltage Level 1, 2 or 3) With Educational Institution (GEI)	Applicable	Applicable
Commercial (Customer Voltage Level 1, 2 or 3) With Self-Generation (SG) **	1745	Not Applicable
Industrial (Customer Voltage Level 1, 2 or 3) With Self-Generation (SG) **	1750	Not Applicable
Net Metering Program	Applicable	Applicable
Green Generation Program	Applicable	Not Applicable
LARGE GENERAL SERVICE PRIMARY DEMAND RATE GPD		
Commercial (Customer Voltage Level 1, 2 or 3)	1220	2220
Industrial (Customer Voltage Level 1, 2 or 3)	1230	2230
Provisions		
Commercial (Customer Voltage Level 1, 2 or 3) Resale	Applicable	Applicable
Industrial (Customer Voltage Level 1, 2 or 3) Resale	Applicable	Applicable
Commercial (Customer Voltage Level 1, 2 or 3) With Aggregate Peak Demand (GAP) **	Applicable	Not Applicable
Industrial (Customer Voltage Level 1, 2 or 3) With Aggregate Peak Demand (GAP) **	Applicable	Not Applicable
Commercial (Customer Voltage Level 1, 2 or 3) With Educational Institution (GEI) **	Applicable	Applicable
Industrial (Customer Voltage Level 1, 2 or 3) With Educational Institution (GEI) **	Applicable	Applicable
Commercial (Customer Voltage Level 1, 2 or 3) With Interruptible (GI)	Applicable	Not Applicable
Industrial (Customer Voltage Level 1, 2 or 3) With Interruptible (GI)	Applicable	Not Applicable
Commercial (Customer Voltage Level 1, 2 or 3) With Interruptible –Market Price (GI2)	Applicable	Not Applicable
Industrial (Customer Voltage Level 1, 2 or 3) With Interruptible – Market Price (GI2)	Applicable	Not Applicable
Commercial (Customer Voltage Level 1, 2 or 3) With Self-Generation (SG) **	1755	Not Applicable
Industrial (Customer Voltage Level 1, 2 or 3) With Self-Generation (SG) **	1760	Not Applicable
Net Metering Program	Applicable	Applicable
Green Generation Program	Applicable	Not Applicable
GENERAL SERVICE PRIMARY TIME-OF-USE RATE GPTU		
Commercial (Customer Voltage Level 1, 2, or 3)	1280	Not Applicable
Industrial (Customer Voltage Level 1, 2, or 3)	1285	Not Applicable
Provisions		
Commercial (Customer Voltage Level 1, 2 or 3) Resale	*Applicable*	*Not Applicable*
Industrial (Customer Voltage Level 1, 2 or 3) Resale	*Applicable*	*Not Applicable*
Commercial with Education Institution (GEI)	Applicable	Applicable
Industrial with Education Institution (GEI)	Applicable	Applicable
Commercial (Customer Voltage Level 1, 2 or 3) With Self-Generation (SG) **	1765	Not Applicable
Industrial (Customer Voltage Level 1, 2 or 3) With Self-Generation (SG) **	1770	Not Applicable
Net Metering Program	Applicable	Not Applicable
Green Generation Program	Applicable	Not Applicable
GENERAL SERVICE ENERGY INTENSIVE PRIMARY RATE EIP		
Industrial (Customer Voltage Level 1, 2, or 3)	1250	Not Applicable
Provisions		
Commercial (Customer Voltage Level 1, 2, or 3) With Self-Generation (SG) **	1775	Not Applicable
Industrial (Customer Voltage Level 1, 2, or 3) With Self-Generation (SG) **	1780	Not Applicable
Green Generation Program	Applicable	Not Applicable

* Provisions shall not be taken in conjunction with the GEI provision or the Net Metering Program.
** Provisions shall not be taken in conjunction with the Net Metering Program.

(Continued on Sheet No. D-7.10)

RESIDENTIAL SUMMER ON-PEAK BASIC RATE

Availability:

Subject to any restrictions, this rate is available to any Full Service Customer desiring electric service for any usual residential use in: (i) private family dwellings; (ii) tourist homes, rooming houses, dormitories, nursing homes and other similarly occupied buildings containing sleeping accommodations for up to six persons; or (iii) existing multifamily dwellings containing up to four households served through a single meter. Service for single-phase or three-phase equipment may be included under this rate, provided the individual capacity of such equipment does not exceed 3 hp or 3 kW, nor does the total connected load of the home exceed 10 kW, without the specific consent of the Company.

The Residential Summer On-Peak Basic Rate Pilot will commence by June 1, 2019. Customer eligibility to participate in the Pilot is determined solely by the Company. Selected customers must remain in the pilot through December 31, 2019.

This rate is not available for: (i) resale purposes; (ii) multifamily dwellings containing more than four living units served through a single meter; (iii) tourist homes, rooming houses, dormitories, nursing homes and similarly occupied buildings containing sleeping accommodations for more than six persons; (iv) any other Non-Residential usage; or (v) Rule C5.5 - Non-Transmitting Meter Provision participants.

Residences in conjunction with commercial or industrial enterprises and mobile home parks may take service on this rate only under the Rules and Regulations contained in the Company's Electric Rate Book.

Nature of Service:

Service under this rate shall be alternating current, 60-Hertz, single-phase or three-phase (at the Company's option) Secondary Voltage service. The Company will determine the particular nature of the voltage in each case.

Monthly Rate:

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

Energy Charge:

Non-Capacity	*Capacity*	*Total*	
$0.061121	*$0.035660*	*$0.096781*	*per kWh for Off-Peak kWh between June 1 and September 30*
$0.090785	*$0.052967*	*$0.143752*	*per kWh for On-Peak kWh between June 1 and September 30*
$0.061121	*$0.035660*	*$0.096781*	*per kWh for all kWh between October 1 and May 31*

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-4.00.

Delivery Charges: ***These charges are applicable to Full Service Customers.***

System Access Charge:	*$7.50*	*per customer per month*
Distribution Charge:	*$0.047054*	*per kWh for all kWh*

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-3.10 and the Power Plant Securitization Charges shown on Sheet No. D-5.10.

(Continued on Sheet No. D-8.20)

RESIDENTIAL SUMMER ON-PEAK BASIC RATE

(Continued From Sheet No. D-8.10)

Monthly Rate: (Contd)

Income Assistance Service Provision (RIA):

When service is supplied to a Principal Residence Customer, where the household receives a Home Heating Credit (HHC) in the State of Michigan, a credit shall be applied during all billing months. For an income assistance customer to qualify for this credit the Company shall require annual evidence of the HHC energy draft or warrant. The customer may also qualify for this credit by meeting the requirements under Rule B2, Consumer Standards and Billing Practices for Electric and Natural Gas Service, R 460.102, Definitions; A to F. Confirmation shall be required by an authorized State or Federal agency to verify that the customer's total household income does not exceed 150% of the Federal poverty level.

The monthly credit for the residential Income Assistance Service Provision shall be applied as follows:

Delivery Charges: These ch

arges are applicable to Full Service Customers.

Income Assistance Credit: $(7.50) per customer per month

This credit shall not be taken in conjunction with a credit for the Senior Citizen Service Provision (RSC).

Senior Citizen Service Provision (RSC):

When service is supplied to the Principal Residence Customer who is 65 years of age or older and head of household, a credit shall be applied during all billing months.

The monthly credit for the residential Senior Citizen Service Provision shall be applied as follows:

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

Senior Citizen Credit: $(3.75) per customer per month

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

Peak Power Savers:
Customers can elect to participate in the Air Conditioning Peak Cycling Program and the Peak Reward Program as described in this tariff. When a customer participates in both programs, the customer's incremental energy savings earned under the Peak Reward is compared to the Peak Power Savers – Air Conditioner Peak Cycling Program Credit. The greater of the two credits will be applied to the customer's invoice for that billing month Both credits will not apply in a single billing month. Customers participating in the Peak Rewards Program cannot participate in the Critical Peak Price Program.

Air Conditioner Peak Cycling Program – (Available on a Date to be Announced by the Company):
A customer in a single family residence who is taking service from the Company may be eligible to participate in the Company's voluntary Peak Power Savers – Air Conditioner Peak Cycling Program for load management of eligible electric central air conditioning, central heat pump, or other qualifying electric equipment. Customer eligibility to participate in this program is determined solely by the Company. The Company will accept a customer's central air conditioning, central heat pump, and other qualifying electric equipment under this program only if it has the capability to be controlled by the Company. Load Management of a customer's swimming pool pump is permitted under this program only if the customer is allowing Load Management of their air conditioner or heat pump unit. The Company will install the required equipment at the customer's premises which will allow Load Management upon signal from the Company. Such equipment shall be furnished, installed, maintained and owned by the Company at the Company's expense. Equipment installations must conform to the Company's specifications.

The Company reserves the right to specify the term or duration of the program. The customer's enrollment shall be terminated if the voluntary program ceases, if the customer tampers with the control switch or the Company's equipment or any reasons as provided for in Rule C1.3, Use of Service.

Load Management may occur any day of the week including weekends between the hours of 7:00 AM and 8:00 PM for no more than an eight hour period in any one day. Load Management may be implemented for, but not limited to, maintaining system integrity, making an emergency purchase, economic reasons, or when there is insufficient system generation available to meet anticipated system load. Load Management may only occur outside of the hours of 7:00 AM and 8:00 PM during a declared emergency event as directed by MISO.

The Customer may contact the Company to request to override a Load Management event for one Load Management event during the June through September months in any one calendar year for the balance of the hours left in that Load Management event with no penalty. The request shall be granted at the discretion of the Company. If the override request was granted by the Company and the customer requests and is granted any additional overrides in the same calendar year, the Peak Power Savers – Air Conditioner Peak Cycling Credit may be forfeited for that billing month.

(Continued on Sheet No. D-8.30

RESIDENTIAL SUMMER ON-PEAK BASIC RATE

(Continued From Sheet No. D-8.20)

Monthly Rate: (Contd)

Peak Power Savers: (Contd)

Air Conditioner Peak Cycling Program: (Contd)

Rule C1.1 Character of Service, Rule C3 Emergency Electrical Procedures and other rules and regulations contained in the Company's Electric Rate Book apply to customers taking service under this Peak Power Savers – Air Conditioner Peak Cycling Program.

The monthly credit for the Peak Power Savers Program shall be applied as follows:

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

Peak Power Savers – Air Conditioner Peak Cycling Credit:	*$(8.00)*	*per customer per month during the billing months of June-September*

Peak Reward – (Available on a Date to be Announced by the Company):

Participating customers are able to manage electric costs by reducing load during critical peak events. The Company may call up to fourteen critical peak events between June 1 and September 30. Customers will be notified by 11:59 PM the day before a critical peak event is expected to occur. Receipt of such notice is the responsibility of the participating customer. Customers must have a transmitting meter to participate in Peak Power Savers.

During a critical peak event, customers on will be credited the Peak Reward per kWh of incremental energy reductions.

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

Peak Reward	*$(0.95)*	*per kWh of incremental energy reduction during a critical peak event between June 1 and September 30*

***Critical Peak Price** – (Available on a Date to be Announced by the Company)*
Participating customers are able to manage electric costs by shifting load during critical peak events to a lower cost pricing period. The Company may call up to fourteen critical peak events between June 1 and September 30. Customers will be notified by 11:59 PM the day before a critical peak event is expected to occur. Receipt of such notice is the responsibility of the participating customer. Customers must have a transmitting meter to participate in Peak Power Savers.

During a critical peak event, customers on will be charged the Critical Peak Price per kWh consumed during the critical peak event.

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

Critical Peak Price	*$0.95*	*per kWh of energy consumed during a critical peak event between June 1 and September 30*
Capacity Discount	*$(0.0XXXXX)*	*per kWh for Off-Peak kWh between June 1 and September 30*

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

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

Energy delivered to the Company shall be alternating current, 60-hertz, single-phase or three-phase (as governed by Rule B8., Electric Interconnection and Net Metering Standards) Secondary Voltage or Primary Voltage service. The Company will determine the particular nature of the voltage in each case.

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

Sales of Self-Generated Energy to the Company:
A customer who meets the Federal Energy Regulatory Commission's (FERC) criteria for a Qualifying Facility may elect to sell energy to the Company. The Company has the right to refuse to contract for the purchase of energy. Sales of energy to the Company under this provision shall require a written contract with a minimum term of one year.

Where the customer elects to sell energy to the Company, an Interval Data Meter (IDM) or other applicable meter is required for their generator. Meter reading will be accomplished electronically through telecommunication links or other electronic data methods able to provide the Company with the metering data / billing determinants necessary for billing purposes.

Administrative Cost Charge: *$0.0010 per kWh purchased for generation installations with a capacity of 550 kW or less.*

Energy Purchase:

An energy purchase by the Company shall be bought at the Midcontinent Independent System Operator's, Inc. (MISO) real-time Locational Marginal Price (LMP) for the Company's load node (designated as "CONS.CETR" as of the date of this Rate Schedule). The Company may discontinue purchases during system emergencies, maintenance and other operational circumstances.

(Continued on Sheet No. D-8.40)

RESIDENTIAL SUMMER ON-PEAK BASIC RATE

(Continued From Sheet No. D-8.30)

Monthly Rate: (Contd)

Net Metering Program:

The Net Metering Program is available to any eligible customer as described in Rule C 11., Net Metering Program, who desires to generate a portion or all of their own retail electricity requirements using a Renewable Energy Resource as defined in Rule C11.B, Net Metering Definitions.

A customer who participates in the Net Metering Program is subject to the provisions contained in Rule C 11., Net Metering Program.

Green Generation Program:

Customer contracts for participation in the Green Generation Program shall be available to any eligible customer as described in Rule C10.2, Green Generation Program.

A customer who participates in the Green Generation Program is subject to the provisions contained in Rule C10.2, Green Generation Program.

General Terms:

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

Schedule of On-Peak and Off-Peak Hours:

The following schedule shall apply Monday through Friday, June 1 through September 30, including weekday holidays when applicable:

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

Saturday and Sunday are Off-Peak.

Minimum Charge:

The System Access Charge included in the rate, adjusted for qualified service provision credit and any applicable non-consumption based surcharges.

Due Date and Late Payment Charge:

The due date of the customer's bill shall be 21 days from the date of transmittal. A late payment charge of 2%, not compounded, of the portion of the bill, net of taxes, shall be assessed to any bill that is delinquent. A customer who participates in the Winter Protection Plan or who is 65 years of age or older and who has notified the Company the customer is 65 years of age or older, shall be exempt from a late payment charge as described in Rule B2., Consumer Standards and Billing Practices for Electric and Natural Gas Service, R 460.125, Late payment charges.

Term and Form of Contract:

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

RESIDENTIAL SERVICE SECONDARY RATE RS

Availability:

Subject to any restrictions, this rate is available to any customer desiring electric service for any usual residential use in: (i) private family dwellings; (ii) tourist homes, rooming houses, dormitories, nursing homes and other similarly occupied buildings containing sleeping accommodations for up to six persons; or (iii) existing multifamily dwellings containing up to four households served through a single meter. Service for single-phase or three-phase equipment may be included under this rate, provided the individual capacity of such equipment does not exceed 3 hp or 3 kW, nor does the total connected load of the home exceed 10 kW, without the specific consent of the Company.

As of January 1, 2020 this rate is closed to new business. After January 1, 2020 this rate is only available to customers electing a Non-Transmitting Meter in accordance with Rule C5.5, Non-Transmitting Meter Provision or customers determined to be eligible at the Company's sole discretion .

This rate is not available for: (i) resale purposes; (ii) multifamily dwellings containing more than four living units served through a single meter; (iii) tourist homes, rooming houses, dormitories, nursing homes and similarly occupied buildings containing sleeping accommodations for more than six persons; or (iv) any other Non-Residential usage.

Residences in conjunction with commercial or industrial enterprises and mobile home parks may take service on this rate only under the Rules and Regulations contained in the Company's Electric Rate Book.

Nature of Service:

Service under this rate shall be alternating current, 60-Hertz, single-phase or three-phase (at the Company's option) Secondary Voltage service. The Company will determine the particular nature of the voltage in each case.

The Company will schedule meter readings on a monthly basis and attempt to obtain an actual meter reading for all tourist and/or occasional residence customers at intervals of not more than six months.

Monthly Rate:

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

Energy Charge:

Non-Capacity	Capacity	Total	
$~~0.061459~~ *0.060483*	$~~0.033144~~ *0.035102*	$~~0.094603~~ *0.095585*	per kWh for the first 600 kWh per month during the billing months of June - September
$~~0.082726~~ *0.079987*	$~~0.044613~~ *0.046421*	$~~0.127339~~ *0.126408*	per kWh for all kWh over 600 kWh per month during the billing months of June - September
$~~0.061459~~ *0.060483*	$~~0.033144~~ *0.035102*	$~~0.094603~~ *0.095585*	per kWh for all kWh during the billing months of October-May

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-4.00.

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

System Access Charge:	$~~7.00~~ *7.50*	per customer per month
Distribution Charge:	$~~0.050510~~ *0.047054*	per kWh for all kWh

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

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-3.10 and the Power Plant Securitization Charges shown on Sheet No. D-5.10.

(Continued on Sheet No. D-10.00)

RESIDENTIAL SERVICE SECONDARY RATE RS

(Continued From Sheet No. D-9.00)

Monthly Rate: (Contd)

Income Assistance Service Provision (RIA):

When service is supplied to a Principal Residence Customer, where the household receives a Home Heating Credit (HHC) in the State of Michigan, a credit shall be applied during all billing months. For an income assistance customer to qualify for this credit the Company shall require annual evidence of the HHC energy draft or warrant. The customer may also qualify for this credit by meeting the requirements under Rule B2, Consumer Standards and Billing Practices for Electric and Natural Gas Service, R 460.102, Definitions; A to F. Confirmation shall be required by an authorized State or Federal agency to verify that the customer's total household income does not exceed 150% of the Federal poverty level.

The monthly credit for the residential Income Assistance Service Provision shall be applied as follows:

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

Income Assistance Credit: $(~~7.00~~ *7.50*) per customer per month

This credit shall not be taken in conjunction with a credit for the Senior Citizen Service Provision (RSC).

RESIDENTIAL SERVICE SECONDARY RATE RS

(Continued From Sheet No. D-10.00)

Monthly Rate: (Contd)

Senior Citizen Service Provision (RSC):

When service is supplied to the Principal Residence Customer who is 65 years of age or older and head of household, a credit shall be applied during all billing months.

The monthly credit for the residential Senior Citizen Service Provision shall be applied as follows:

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

Senior Citizen Credit: $(~~3.50~~ *3.75*) per customer per month

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

Self-Generation Provision (SG):

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

All facilities must meet the Parallel Operation Requirements set forth in Rule C1.6 B. The Company shall own, operate and maintain all metering and auxiliary devices (including telecommunication links) at the customer's expense. Meters furnished, installed and maintained by the Company shall meter generation equipment for customers that sell energy to the Company. No refund shall be made for any customer contribution required.
Energy delivered to the Company shall be alternating current, 60-hertz, single-phase or three-phase (as governed by Rule B8., Electric Interconnection and Net Metering Standards) Secondary Voltage or Primary Voltage service. The Company will determine the particular nature of the voltage in each case.
Self-generation customers requiring Company delivery service for any portion of the load that has been self-generated will be charged as described in the Delivery Charges section of this Rate Schedule.

Sales of Self-Generated Energy to the Company:

A customer who meets the Federal Energy Regulatory Commission's (FERC) criteria for a Qualifying Facility may elect to sell energy to the Company. The Company has the right to refuse to contract for the purchase of energy. Sales of energy to the Company under this provision shall require a written contract with a minimum term of one year.

Where the customer elects to sell energy to the Company, an Interval Data Meter (IDM) or other applicable meter is required for their generator. Meter reading will be accomplished electronically through telecommunication links or other electronic data methods able to provide the Company with the metering data / billing determinants necessary for billing purposes.

Administrative Cost Charge: $0.0010 per kWh purchased for generation installations with a capacity of ~~100~~ *550* kW or less.

Energy Purchase:

An energy purchase by the Company shall be bought at the Midcontinent Independent System Operator's, Inc. (MISO) real-time Locational Marginal Price (LMP) for the Company's load node (designated as "CONS.CETR" as of the date of this Rate Schedule). The Company may discontinue purchases during system emergencies, maintenance and other operational circumstances.

(Continued on Sheet No. D-11.10)

RESIDENTIAL SERVICE SECONDARY RATE RS

(Continued From Sheet No. D-11.00)

Monthly Rate: (Contd)

Peak Power Savers – Air Conditioner Peak Cycling Program:

A customer in a single family residence who is taking service from the Company may be eligible to participate in the Company's voluntary Peak Power Savers – Air Conditioner Peak Cycling Program for load management of eligible electric central air conditioning, central heat pump, or other qualifying electric equipment. Customer eligibility to participate in this program is determined solely by the Company. The customer must be located within an area in which Advanced Metering Infrastructure (AMI) is deployed and have a fully operational AMI meter for purposes of this program. The Company will accept a customer's central air conditioning, central heat pump, and other qualifying electric equipment under this program only if it has the capability to be controlled by the Company. Load Management of a customer's swimming pool pump is permitted under this program only if the customer is allowing Load Management of their air conditioner or heat pump unit. The Company will install the required equipment at the customer's premises which will allow Load Management upon signal from the Company. Such equipment shall be furnished, installed, maintained and owned by the Company at the Company's expense. Equipment installations must conform to the Company's specifications.

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

Load Management may occur any day of the week including weekends between the hours of 7:00 AM and 8:00 PM for no more than an eight hour period in any one day. Load Management may be implemented for, but not limited to, maintaining system integrity, making an emergency purchase, economic reasons, or when there is insufficient system generation available to meet anticipated system load. Load Management may only occur outside of the hours of 7:00 AM and 8:00 PM during a declared emergency event as directed by MISO.

The Customer may contact the Company to request to override a Load Management event for one Load Management event during the June through September months in any one calendar year for the balance of the hours left in that Load Management event with no penalty. The request shall be granted at the discretion of the Company. If the override request was granted by the Company and the customer requests and is granted any additional overrides in the same calendar year, the Peak Power Savers Credit may be forfeited for that billing month.

Rule C1.1 Character of Service, Rule C3 Emergency Electrical Procedures and other rules and regulations contained in the Company's Electric Rate Book apply to customers taking service under this Peak Power Savers – Air Conditioner Peak Cycling Program.

The monthly credit for the Peak Power Savers – Air Conditioner Peak Cycling Program shall be applied as follows:

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

Peak Power Savers – Air Conditioner Peak Cycling Credit: $(*8.00* ~~7.84~~) per customer per month during the billing months of June-September

(Continued on Sheet No. D-11.20)

RESIDENTIAL DYNAMIC PRICING PROGRAM

(Continued From Sheet No. D-13.00)

Monthly Rate:

Option 1 – Peak Power Savers - Critical Peak Time-of-Use Rate (RDP):

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

Energy Charge:

	Non-Capacity	Capacity	Total	
Off-Peak – Summer	$ ~~0.041772~~ *0.048820*	$ ~~0.017709~~ *0.028333*	$~~0.059481~~ *0.077153*	per kWh for all Off-Peak kWh ~~during the billing months of June-September~~ *between June 1 and September 30*
Mid-Peak – Summer	$ ~~0.058218~~ *0.069461*	$ ~~0.024681~~ *0.040312*	$~~0.082899~~ *0.109773*	per kWh for all Mid-Peak kWh ~~during the billing months of June-September~~ *between June 1 and September 30*
On-Peak – Summer	$ ~~0.072892~~ *0.088400*	$ ~~0.030902~~ *0.051304*	$~~0.103794~~ *0.139704*	per kWh for all On-Peak kWh ~~during the billing months of June-September between~~ *June 1 and September 30*
Off-Peak – Winter	$ ~~0.057140~~ *0.048820*	$ ~~0.030815~~ *0.028333*	$~~0.087955~~ *0.077153*	per kWh for all Off-Peak kWh ~~during the billing months of October-May~~ *between October 1 and May 31*
On-Peak – Winter	$ ~~0.065872~~ *0.061087*	$ ~~0.035524~~ *0.035452*	$~~0.101396~~ *0.096539*	per kWh for all On-Peak kWh ~~during the billing months of October-May~~ *between October 1 and May 31*
Critical Peak Event	$ ~~0.611119~~ *0.601129*	$ ~~0.338881~~ *0.348871*	$0.950000	per kWh during a critical peak event between June 1 and September 30

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-4.00

Delivery Charges: **These charges are applicable to Full Service Customers.**

System Access Charge:-	~~$7.00~~ *7.50*	per customer per month
Distribution Charge:-	$ ~~0.050510~~ *0.047054*	per kWh for all kWh for a Full Service Customer

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-3.10 and the Power Plant Securitization Charges shown on Sheet No. D-5.10.

Option 2 – Peak Power Savers - Peak Rewards Time-of-Use Rate RDPR:

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

Energy Charge:

	Non-Capacity	Capacity	Total	
Off-Peak-Summer	~~$ 0.050506~~ *0.057112*	~~$ 0.027125~~ *0.033146*	~~$0.077631~~ *0.090258*	per kWh for all Off-Peak kWh ~~during the billing months of June-September~~ *between June 1 and September 30*
Mid-Peak-Summer	~~$ 0.070391~~ *0.081003*	~~$ 0.037804~~ *0.047012*	~~$0.108195~~ *0.128015*	per kWh for all Mid-Peak kWh ~~during the billing months of June-September~~ *between June 1 and September 30*
On-Peak-Summer	~~$ 0.088134~~ *0.102910*	~~$ 0.047333~~ *0.059726*	~~$0.13467~~ *0.162636*	per kWh for all On-Peak kWh ~~during the billing months of June-September~~ *between June 1 and September 30*
Off-Peak-Winter	~~$ 0.057140~~ *0.048820*	~~$ 0.030815~~ *0.028333*	~~$0.087955~~ *0.077153*	per kWh for all Off-Peak kWh ~~during the billing months of October-May~~ *between October 1 and May 31*
On-Peak -Winter	~~$ 0.065872~~ *0.061087*	~~$ 0.035524~~ *0.035452*	~~$0.101396~~ *0.096539*	per kWh for all On-Peak kWh ~~during the billing months of October-May~~ *between October 1 and May 31*
Critical Peak Reward	$(~~0.611119~~) *(0.601129)*	$(~~0.33881~~) *(0.348871)*	$(0.950000)	per kWh during a critical peak event between June 1 and September 30

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-4.00.

(Continued on Sheet No. D-13.02)

RESIDENTIAL DYNAMIC PRICING PROGRAM

(Continued From Sheet No. D-13.01)

Monthly Rate: (Contd)

Option 2 – Peak Power Savers – Peak Rewards Time-of-Use Rate RDPR: (Contd)

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

System Access Charge:	$~~7.00~~ *7.50*	per customer per month
Distribution Charge:	$~~0.050510~~ *0.047054*	per kWh for all kWh for a Full Service customer

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-3.10 and the Power Plant Securitization Charges shown on Sheet No. D-5.10.

Income Assistance Service Provision (RIA):

When service is supplied to a Principal Residence Customer, where the household receives a Home Heating Credit (HHC) in the State of Michigan, a credit shall be applied during all billing months. For an income assistance customer to qualify for this credit the Company shall require annual evidence of the HHC energy draft or warrant. The customer may also qualify for this credit by meeting the requirements under Rule B2., Consumer Standards and Billing Practices for Electric and Natural Gas Service, R 460.102, Definitions; A to F. Confirmation shall be required by an authorized State or Federal agency to verify that the customer's total household income does not exceed 150% of the Federal poverty level.

The monthly credit for the residential Income Assistance Service Provision shall be applied as follows:

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

Income Assistance Credit: $(~~7.00~~ *7.50*) per customer per month

This credit shall not be taken in conjunction with a credit for the Senior Citizen Service Provision (RSC).

Senior Citizen Service Provision (RSC):

When service is supplied to the Principal Residence Customer who is 65 years of age or older and head of household, a credit shall be applied during all billing months.

The monthly credit for the residential Senior Citizen Service Provision shall be applied as follows:

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

Senior Citizen Credit: $(~~3.50~~ *3.75*) per customer per month

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

(Continued on Sheet No. D-13.03)

RESIDENTIAL DYNAMIC PRICING PROGRAM

(Continued From Sheet No. D-13.02)

Monthly Rate: (Contd)

Self-Generation Provision (SG):

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

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

Energy delivered to the Company shall be alternating current, 60-hertz, single-phase or three-phase (as governed by Rule B8., Electric Interconnection and Net Metering Standards) Secondary Voltage or Primary Voltage service. The Company will determine the particular nature of the voltage in each case.

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

Sales of Self-Generated Energy to the Company:

A customer who meets the Federal Energy Regulatory Commission's (FERC) criteria for a Qualifying Facility may elect to sell energy to the Company. The Company has the right to refuse to contract for the purchase of energy. Sales of energy to the Company under this provision shall require a written contract with a minimum term of one year.

Where the customer elects to sell energy to the Company, an Interval Data Meter (IDM) or other applicable meter is required for their generator. Meter reading will be accomplished electronically through telecommunication links or other electronic data methods able to provide the Company with the metering data / billing determinants necessary for billing purposes.

Administrative Cost Charge: $0.0010 per kWh purchased for generation installations with a capacity of ~~100~~ *550* kW or less.

Energy Purchase:

An energy purchase by the Company shall be bought at the Midcontinent Independent System Operator's, Inc. (MISO) real-time Locational Marginal Price (LMP) for the Company's load node (designated as "CONS.CETR" as of the date of this Rate Schedule). The Company may discontinue purchases during system emergencies, maintenance and other operational circumstances.

Green Generation Program:

Customer contracts for participation in the Green Generation Program shall be available to any eligible customer as described in Rule C10.2, Green Generation Program.

A customer who participates in the Green Generation Program is subject to the provisions contained in Rule C10.2, Green Generation Program.

General Terms:

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

Minimum Charge:

The System Access Charge included in the rate, adjusted for qualified service provision credit and any applicable non-consumption based surcharges.

(Continued on Sheet No. D-13.04)

EXPERIMENTAL RESIDENTIAL PLUG-IN ELECTRIC VEHICLE CHARGING PROGRAM

Availability:

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

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

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

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

"Level 2 Charging" is defined as voltage connection of either 240 volts or 208 volts and a maximum load of 32 amperes or 7.7 kVA at 240 volts or 6.7 kVA at 208 volts.

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

Vehicles shall be registered and operable on public highways in the State of Michigan to qualify for this rate. Low-speed electric vehicles including golf carts are not eligible to take service under this rate even if licensed to operate on public streets. The customer may be required to provide proof of registration of the electric vehicle to qualify for program.

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

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

Nature of Service:

Service under this rate shall be alternating current, 60-Hertz, single-phase or three-phase (at the Company's option) Secondary Voltage service.

Monthly Rate:

Option 1 – REV-1:

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

Energy Charge:

	Non-Capacity	Capacity	Total	
Off-Peak – Summer	$ ~~0.054616~~ *0.049127*	$ ~~0.029411~~ *0.028511*	$~~0.084027~~ *0.077638*	per kWh for all Off-Peak kWh ~~during the billing months of June-September~~ *between June 1 and September 30*
Mid-Peak – Summer	$ ~~0.076120~~ *0.073691*	$ ~~0.040991~~ *0.042767*	$~~0.117111~~ *0.116458*	per kWh for all Mid-Peak kWh ~~during the billing months of June-September~~ *between June 1 and September 30*
On-Peak – Summer	$ ~~0.095305~~ *0.117906*	$ ~~0.051322~~ *0.068427*	$~~0.146627~~ *0.186333*	per kWh for all On-Peak kWh ~~during the billing months of June-September~~ *between June 1 and September 30*
Off-Peak – Winter	$ ~~0.054616~~ *0.049127*	$ ~~0.029411~~ *0.028511*	$~~0.084027~~ *0.077638*	per kWh for all Off-Peak kWh ~~during the billing months of October-May~~ *between October 1 and May 31*
On-Peak – Winter	$ ~~0.062963~~ *0.073691*	$ ~~0.033906~~ *0.042767*	~~$0.096869~~ *0.116458*	per kWh for all On-Peak kWh ~~during the billing months of October-May~~ *between October 1 and May 31*

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-4.00.

(Continued on Sheet No. D-13.20)

EXPERIMENTAL RESIDENTIAL PLUG-IN ELECTRIC VEHICLE CHARGING PROGRAM

(Continued From Sheet No. D-13.10)

Monthly Rate (Contd)

Option 1 – REV – 1 (Contd)

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

System Access Charge:	$~~7.00~~ *7.50*	per customer per month
Distribution Charge:	$~~0.050510~~ *0.047054*	per kWh for all kWh for a Full Service customer

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-3.10 and the Power Plant Securitization Charges shown on Sheet No. D-5.10.

General Terms:

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

Self-Generation Provision (SG):

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

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

Energy delivered to the Company shall be alternating current, 60-hertz, single-phase or three-phase (as governed by Rule B8., Electric Interconnection and Net Metering Standards) Secondary Voltage or Primary Voltage service. The Company will determine the particular nature of the voltage in each case.

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

Sales of Self-Generated Energy to the Company:

A customer who meets the Federal Energy Regulatory Commission's (FERC) criteria for a Qualifying Facility may elect to sell energy to the Company. The Company has the right to refuse to contract for the purchase of energy. Sales of energy to the Company under this provision shall require a written contract with a minimum term of one year.

Where the customer elects to sell energy to the Company, an Interval Data Meter (IDM) or other applicable meter is required for their generator. Meter reading will be accomplished electronically through telecommunication links or other electronic data methods able to provide the Company with the metering data / billing determinants necessary for billing purposes.

Administrative Cost Charge:

$0.0010 per kWh purchased for generation installations with a capacity of ~~100~~ *550* kW or less.

Energy Purchase:

An energy purchase by the Company shall be bought at the Midcontinent Independent System Operator's, Inc. (MISO) real-time Locational Marginal Price (LMP) for the Company's load node (designated as "CONS.CETR" as of the date of this Rate Schedule). The Company may discontinue purchases during system emergencies, maintenance and other operational circumstance.

(Continued on Sheet No. D-13.25)

EXPERIMENTAL RESIDENTIAL PLUG-IN ELECTRIC VEHICLE CHARGING PROGRAM

(Continued From Sheet No. D-13.20)

Monthly Rate (Contd)

Option 2 - REV-2:

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

Energy Charge:

	Non-Capacity	Capacity	Total	
Off-Peak – Summer	$ ~~0.054616~~ *0.049127*	$ ~~0.029411~~ *0.028511*	$~~0.084027~~ *0.077638*	per kWh for all Off-Peak kWh ~~during the billing months of June-September~~ *between June 1 and September 30*
Mid-Peak – Summer	$ ~~0.076120~~ *0.073691*	$ ~~0.040991~~ *0.042767*	$~~0.117111~~ *0.116458*	per kWh for all Mid-Peak kWh ~~during the billing months of June-September~~ *between June 1 and September 30*
On-Peak – Summer	$ ~~0.095305~~ *0.117906*	$ ~~0.051322~~ *0.068427*	$~~0.146627~~ *0.186333*	per kWh for all On-Peak kWh ~~during the billing months of June-September~~ *between June 1 and September 30*
Off-Peak – Winter	$ ~~0.054616~~ *0.049127*	$ ~~0.029411~~ *0.028511*	$~~0.084027~~ *0.077638*	per kWh for all Off-Peak kWh ~~during the billing months of October-May~~ *between October 1 and May 31*
On-Peak – Winter	$ ~~0.062963~~ *0.073691*	$ ~~0.033906~~ *0.042767*	$~~0.096869~~ *0.116458*	per kWh for all On-Peak kWh ~~during the billing months of October-May~~ *between October 1 and May 31*

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-4.00.

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

Distribution Charge: $~~0.050510~~ *0.047054* for all kWh

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

General Terms:

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

(Continued on Sheet No. D-13.30)

RESIDENTIAL SERVICE TIME-OF-DAY SECONDARY RATE RT

Availability:

Subject to any restrictions, this rate is available to any residential customer desiring electric service who chooses to have their electric consumption metered based upon on-peak and off-peak periods. In addition, this rate is available to customers desiring electric service for electric vehicle battery charging where such service is in addition to all other household requirements. Battery charging service is limited to four-wheel vehicles licensed for operation on public streets and highways. Service for single-phase or three-phase equipment may be included under this rate, provided the individual capacity of such equipment does not exceed 3 hp or 3 kW, nor does the total connected load of the home exceed 10 kW, without the specific consent of the Company.

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

This rate is not available for resale purposes or for any Non-Residential usage.

Nature of Service:

Service under this rate shall be alternating current, 60-Hertz, single-phase or three-phase (at the Company's option) Secondary Voltage service. The Company will determine the particular nature of the voltage in each case.

Monthly Rate:

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

	Non-Capacity	Capacity	Total	
On-Peak - Summer	$~~0.80976~~ *0.078143*	$~~0.032182~~ *0.045351*	$~~0.113158~~ *0.123494*	per kWh for all On-Peak kWh ~~during the billing months of June September~~ *between June 1 and September 30*
Off-Peak - Summer	$~~0.056108~~ *0.053674*	$~~0.022299~~ *0.031150*	$~~0.078407~~ *0.084824*	per kWh for all Off-Peak kWh ~~during the billing months of June – September~~ *between June 1 and September 30*
On-Peak - Winter	$~~0.065314~~ *0.065300*	$~~0.025958~~ *0.037898*	$~~0.091272~~ *0.103198*	per kWh for all On-Peak kWh ~~during the billing months of October – May~~ *between October 1 and May 31*
Off-Peak - Winter	$~~0.058042~~ *0.057190*	$~~0.023068~~ *0.033191*	$~~0.081110~~ *0.090381*	per kWh for all Off-Peak kWh ~~during the billing months of October - May~~ *between October 1 and May 31*

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-4.00.

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

System Access Charge:	$~~7.00~~ *7.50*	per customer per month
Distribution Charge:	$~~0.050510~~ *0.047054*	per kWh for all kWh for a Full Service customer

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-3.10 and the Power Plant Securitization Charges shown on Sheet No. D-5.10.

Income Assistance Service Provision (RIA):

When service is supplied to a Principal Residence Customer, where the household receives a Home Heating Credit (HHC) in the State of Michigan, a credit shall be applied during all billing months. For an income assistance customer to qualify for this credit, the Company shall require annual evidence of the HHC energy draft or warrant. The customer may also qualify for this credit by meeting the requirements under Rule B2., Consumer Standards and Billing Practices for Electric and Natural Gas Service, R 460.102 Definitions; A to F. Confirmation shall be required by an authorized State or Federal agency to verify that the customer’s total household income does not exceed 150% of the Federal poverty level.

The monthly credit for the residential Income Assistance Service Provision shall be applied as follows:

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

Income Assistance Credit: $(~~7.00~~ *7.50*) per customer per month

This credit shall not be taken in conjunction with a credit for the Senior Citizen Service Provision (RSC).

(Continued on Sheet No. D-15.00)

RESIDENTIAL SERVICE TIME-OF-DAY-SECONDARY RATE RT

(Continued From Sheet No. D-14.00)

Monthly Rate: (Contd)

Senior Citizen Service Provision (RSC):

When service is supplied to the Principle Residence Customer who is 65 years of age or older and head of household, a credit shall be applied during all billing months.

The monthly credit for the residential Senior Citizen Service Provision shall be applied as follows:

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

Senior Citizen Credit: $(~~3.50~~ *3.75*) per customer per month

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

Self-Generation Provision (SG):

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

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

Energy delivered to the Company shall be alternating current, 60-hertz, single-phase or three-phase (as governed by Rule B8., Electric Interconnection and Net Metering Standards) Secondary Voltage or Primary Voltage service. The Company will determine the particular nature of the voltage in each case.

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

Sales of Self-Generated Energy to the Company:

A customer who meets the Federal Energy Regulatory Commission's (FERC) criteria for a Qualifying Facility may elect to sell energy to the Company. The Company has the right to refuse to contract for the purchase of energy. Sales of energy to the Company under this provision shall require a written contract with a minimum term of one year.

Where the customer elects to sell energy to the Company, an Interval Data Meter (IDM) or other applicable meter is required for their generator. Meter reading will be accomplished electronically through telecommunication links or other electronic data methods able to provide the Company with the metering data / billing determinants necessary for billing purposes.

Administrative Cost Charge:

$0.0010 per kWh purchased for generation installations with a capacity of ~~100~~ *550* kW or less.

Energy Purchase:

An energy purchase by the Company shall be bought at the Midcontinent Independent System Operator's, Inc. (MISO) real-time Locational Marginal Price (LMP) for the Company's load node (designated as "CONS.CETR" as of the date of this Rate Schedule). The Company may discontinue purchases during system emergencies, maintenance and other operational circumstance.

(Continued on Sheet No. D-16.00)

RESIDENTIAL SMART HOURS RATE

Availability:

The Residential Smart Hours Rate will be available on a date to be announced by the Company.

Subject to any restrictions, this rate is available to Full Service residential customers who have the required metering equipment and infrastructure installed. The Company will furnish, maintain and own the required equipment at the customers' premises at the Company's expense. By selecting this rate schedule, the customer agrees to provide and email address. Electric consumption is billed using on-peak and off-peak periods year-round on the Residential Smart Hours Rate.

Customers are able to manage electric costs by reducing load during high cost pricing periods or shifting load from high cost pricing periods to lower cost pricing periods. During a critical peak event, customers on the Residential Smart Hours Rate will be credited the Peak Reward per kWh of incremental energy reductions.

The Company may call up to fourteen critical peak events between June 1 and September 30. Customers will be notified by 11:59 PM the day before a critical peak event is expected to occur. Receipt of such notice is the responsibility of the participating customer.

This rate is not available for resale purposes or for any Non-Residential usage.

Nature of Service:

Service under this rate shall be alternating current, 60-Hertz, single-phase or three-phase (at the Company's option) Secondary Voltage service. The Company will determine the particular nature of the voltage in each case.

Monthly Rate:

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

	Non-Capacity	*Capacity*	*Total*	
Off-Peak - Summer	*$0.059280*	*$0.034404*	*$0.093684*	*per kWh for all Off-Peak kWh between June 1 and September 30*
On-Peak - Summer	*$0.088051*	*$0.051101*	*$0.139152*	*per kWh for all On-Peak kWh between June 1 and September 30*
Off-Peak - Winter	*$0.059280*	*$0.034404*	*$0.093684*	*per kWh for all Off-Peak kWh between October 1 and May 31*
On-Peak - Winter	*$0.066561*	*$0.038629*	*$0.105190*	*per kWh for all On-Peak kWh between October 1 and*

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-4.00.

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

System Access Charge:	*$7.50*	*per customer per month*
Distribution Charge:	*$0.047054*	*per kWh for all kWh for a Full Service customer*

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-3.10 and the Power Plant Securitization Charges shown on Sheet No. D-5.10.

Income Assistance Service Provision (RIA):

When service is supplied to a Principal Residence Customer, where the household receives a Home Heating Credit (HHC) in the State of Michigan, a credit shall be applied during all billing months. For an income assistance customer to qualify for this credit, the Company shall require annual evidence of the HHC energy draft or warrant. The customer may also qualify for this credit by meeting the requirements under Rule B2., Consumer Standards and Billing Practices for Electric and Natural Gas Service, R 460.102 Definitions; A to F. Confirmation shall be required by an authorized State or Federal agency to verify that the customer's total household income does not exceed 150% of the Federal poverty level.

The monthly credit for the residential Income Assistance Service Provision shall be applied as follows:

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

Income Assistance Credit: *$(7.50)* *per customer per month*

This credit shall not be taken in conjunction with a credit for the Senior Citizen Service Provision (RSC).

(Continued on Sheet No. D-16.20)

RESIDENTIAL SMART HOURS RATE

(Continued From Sheet No. D-16.10)

Monthly Rate: (Contd)

Senior Citizen Service Provision (RSC):

When service is supplied to the Principle Residence Customer who is 65 years of age or older and head of household, a credit shall be applied during all billing months.

The monthly credit for the residential Senior Citizen Service Provision shall be applied as follows:

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

Senior Citizen Credit: *$(3.75)* *per customer per month*

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

Peak Power Savers:
Customers can elect to participate in the Air Conditioning Peak Cycling Program and the Peak Reward Program as described in this tariff. When a customer participates in both programs, the customer's incremental energy savings earned under the Peak Reward is compared to the Peak Power Savers – Air Conditioner Peak Cycling Program Credit. The greater of the two credits will be applied to the customer's invoice for that billing month Both credits will not apply in a single billing month. Customers participating in the Peak Rewards Program cannot participate in the Critical Peak Price Program.

Air Conditioner Peak Cycling Program – (Available on a Date to be Announced by the Company):
A customer in a single family residence who is taking service from the Company may be eligible to participate in the Company's voluntary Peak Power Savers – Air Conditioner Peak Cycling Program for load management of eligible electric central air conditioning, central heat pump, or other qualifying electric equipment. Customer eligibility to participate in this program is determined solely by the Company. The Company will accept a customer's central air conditioning, central heat pump, and other qualifying electric equipment under this program only if it has the capability to be controlled by the Company. Load Management of a customer's swimming pool pump is permitted under this program only if the customer is allowing Load Management of their air conditioner or heat pump unit. The Company will install the required equipment at the customer's premises which will allow Load Management upon signal from the Company. Such equipment shall be furnished, installed, maintained and owned by the Company at the Company's expense. Equipment installations must conform to the Company's specifications.

The Company reserves the right to specify the term or duration of the program. The customer's enrollment shall be terminated if the voluntary program ceases, if the customer tampers with the control switch or the Company's equipment or any reasons as provided for in Rule C1.3, Use of Service.

Load Management may occur any day of the week including weekends between the hours of 7:00 AM and 8:00 PM for no more than an eight hour period in any one day. Load Management may be implemented for, but not limited to, maintaining system integrity, making an emergency purchase, economic reasons, or when there is insufficient system generation available to meet anticipated system load. Load Management may only occur outside of the hours of 7:00 AM and 8:00 PM during a declared emergency event as directed by MISO.

The Customer may contact the Company to request to override a Load Management event for one Load Management event during the June through September months in any one calendar year for the balance of the hours left in that Load Management event with no penalty. The request shall be granted at the discretion of the Company. If the override request was granted by the Company and the customer requests and is granted any additional overrides in the same calendar year, the Peak Power Savers – Air Conditioner Peak Cycling Credit may be forfeited for that billing month.

Rule C1.1 Character of Service, Rule C3 Emergency Electrical Procedures and other rules and regulations contained in the Company's Electric Rate Book apply to customers taking service under this Peak Power Savers – Air Conditioner Peak Cycling Program.

The monthly credit for the Peak Power Savers Program shall be applied as follows:

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

Peak Power Savers – Air Conditioner Peak Cycling Credit: *$(8.00)* *per customer per month during the billing months of June-September*

(Continued on Sheet No. D-16.30)

RESIDENTIAL SMART HOURS RATE

(Continued From Sheet No. D-16.20)

Monthly Rate: (Contd)

Peak Power Savers: (Contd)

Peak Reward – (Available on a Date to be Announced by the Company):

Participating customers are able to manage electric costs by reducing load during critical peak events. The Company may call up to fourteen critical peak events between June 1 and September 30. Customers will be notified by 11:59 PM the day before a critical peak event is expected to occur. Receipt of such notice is the responsibility of the participating customer. Customers must have a transmitting meter to participate in Peak Power Savers.

During a critical peak event, customers on will be credited the Peak Reward per kWh of incremental energy reductions.

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

Peak Reward	*$(0.95)*	*per kWh of incremental energy reduction during a critical peak event between June 1 and September 30*

***Critical Peak Price** – (Available on a Date to be Announced by the Company)*

Participating customers are able to manage electric costs by shifting load during critical peak events to a lower cost pricing period. The Company may call up to fourteen critical peak events between June 1 and September 30. Customers will be notified by 11:59 PM the day before a critical peak event is expected to occur. Receipt of such notice is the responsibility of the participating customer. Customers must have a transmitting meter to participate in Peak Power Savers.

During a critical peak event, customers on will be charged the Critical Peak Price per kWh consumed during the critical peak event.

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

Critical Peak Price	*$0.95*	*per kWh of energy consumed during a critical peak event between June 1 and September 30*
Capacity Discount	*$(0.0XXXXX)*	*per kWh for Off-Peak kWh between June 1 and September 30*

Self-Generation Provision (SG):

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

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

Energy delivered to the Company shall be alternating current, 60-hertz, single-phase or three-phase (as governed by Rule B8., Electric Interconnection and Net Metering Standards) Secondary Voltage or Primary Voltage service. The Company will determine the particular nature of the voltage in each case.

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

Sales of Self-Generated Energy to the Company:

A customer who meets the Federal Energy Regulatory Commission's (FERC) criteria for a Qualifying Facility may elect to sell energy to the Company. The Company has the right to refuse to contract for the purchase of energy. Sales of energy to the Company under this provision shall require a written contract with a minimum term of one year.

Where the customer elects to sell energy to the Company, an Interval Data Meter (IDM) or other applicable meter is required for their generator. Meter reading will be accomplished electronically through telecommunication links or other electronic data methods able to provide the Company with the metering data / billing determinants necessary for billing purposes.

Attachment 2
To Settlement Agreement In Case No. U-20134

Administrative Cost Charge:

$0.0010 per kWh purchased for generation installations with a capacity of 550 kW or less.

Energy Purchase:

An energy purchase by the Company shall be bought at the Midcontinent Independent System Operator's, Inc. (MISO) real-time Locational Marginal Price (LMP) for the Company's load node (designated as "CONS.CETR" as of the date of this Rate Schedule). The Company may discontinue purchases during system emergencies, maintenance and other operational circumstance.

(Continued on Sheet No. D-16.40)

RESIDENTIAL SMART HOURS RATE

(Continued From Sheet No. D-16.30)

Monthly Rate: (Contd)

Net Metering Program:

The Net Metering Program is available to any eligible customer as described in Rule C11., Net Metering Program, who desires to generate a portion or all of their own retail electricity requirements using a Renewable Energy Resource as defined in Rule C11.B., Net Metering Definitions.

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

Green Generation Program:

Customer contracts for participation in the Green Generation Program shall be available to any eligible customer as described in Rule C10.2., Green Generation Program.

A customer who participates in the Green Generation Program is subject to the provisions contained in Rule C10.2., Green Generation Program.

General Terms:

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

Minimum Charge:

The System Access Charge included in the rate, adjusted for qualified service provision credit and any applicable non-consumption based surcharges.

Due Date and Late Payment Charge:

The due date of the customer's bill shall be 21 days from the date of transmittal. A late payment charge of 2%, not compounded, of the portion of the bill, net of taxes, shall be assessed to any bill that is delinquent. A customer who participates in the Winter Protection Plan or who is 65 years of age or older and who has notified the Company the customer is 65 years of age or older, shall be exempt from a late payment charge as described in Rule B2., Consumer Standards and Billing Practices for Electric and Natural Gas Service, R 460.125, Late payment charges.

Schedule of On-Peak and Off-Peak Hours:

The following schedule shall apply Monday through Friday, including weekday holidays when applicable:

Summer: June 1 through September 30
Winter: October 1 through May 31

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

Saturday and Sunday are Off-Peak.

Term and Form of Contract:

Service under this rate shall not require a written contract.

RESIDENTIAL NIGHTTIME SAVERS RATE

Availability:

The Residential Nighttime Savers Rate will be available on a date to be announced by the Company.

The Residential Nighttime Savers Rate is voluntary and available to Full Service residential customers who have the required metering equipment and infrastructure installed. The Company will furnish, install, maintain and own the required equipment at the customers' premises at the Company's expense. By selecting this rate schedule, the customer agrees to provide an email address.

Customers taking service on the Residential Nighttime Savers Rate are able to manage electric costs by reducing load during high cost pricing periods and shifting load from high cost pricing periods to lower cost pricing periods. During a critical peak event, customers on the Residential Nighttime Savers Rate will be credited the Peak Reward per kWh of incremental energy reductions.

The Company may call up to fourteen critical peak events between June 1 and September 30. Customers will be notified by 11:59 PM the day before a critical peak event is expected to occur. Receipt of such notice is the responsibility of the participating customer.

This rate is not available for: (i) resale purposes; (ii) multifamily dwellings containing more than four living units served through a single meter; (iii) tourist homes, rooming houses, dormitories, nursing homes and similarly occupied buildings containing sleeping accommodations for more than six persons; (iv) any other Non-Residential usage or (v) customers being served under Rule C5.5 Non-Transmitting Meter Provision.

Residences in conjunction with commercial or industrial enterprises and mobile home parks may take service on this program only under the Rules and Regulations contained in the Company's Electric Rate Book.

Nature of Service:

Service under this program shall be alternating current, 60-Hertz, single-phase or three-phase (at the Company's option) Secondary Voltage service. The Company will determine the particular nature of the voltage in each case.

Monthly Rate:

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

Energy Charge:

	Non-Capacity	Capacity	Total	
Super Off-Peak - Summer	$0.047573	$0.027609	$0.075182	per kWh for all Off-Peak kWh between June 1 and September 30
Off-Peak - Summer	$0.080874	$0.046936	$0.127810	per kWh for all Mid-Peak kWh between June 1 and September 30
On-Peak - Summer	$0.095146	$0.055219	$0.150365	per kWh for all On-Peak kWh between June 1 and September 30
Super Off-Peak – Winter	$0.047573	$0.027609	$0.075182	per kWh for all Off-Peak kWh between June 1 and September 30
Off-Peak - Winter	$0.061845	$0.035892	$0.097737	per kWh for all Off-Peak kWh between October 1 and May 31
On-Peak - Winter	$0.066602	$0.038653	$0.105255	per kWh for all On-Peak kWh between

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-4.00.

(Continued on Sheet No. D-17.10)

RESIDENTIAL NIGHTTIME SAVERS RATE

(Continued From Sheet No. D-17.00)

Monthly Rate: (Contd)

Delivery Charges: *These charges are applicable to Full Service Customers.*

System Access Charge:	*$7.50*	*per customer per month*
Distribution Charge:	*$0.047054*	*per kWh for all kWh for a Full Service Customer*

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-3.10 and the Power Plant Securitization Charges shown on Sheet No. D-5.10.

Income Assistance Service Provision (RIA):

When service is supplied to a Principal Residence Customer, where the household receives a Home Heating Credit (HHC) in the State of Michigan, a credit shall be applied during all billing months. For an income assistance customer to qualify for this credit the Company shall require annual evidence of the HHC energy draft or warrant. The customer may also qualify for this credit by meeting the requirements under Rule B2., Consumer Standards and Billing Practices for Electric and Natural Gas Service, R 460.102, Definitions; A to F. Confirmation shall be required by an authorized State or Federal agency to verify that the customer's total household income does not exceed 150% of the Federal poverty level.

The monthly credit for the residential Income Assistance Service Provision shall be applied as follows:

Delivery Charges: *These charges are applicable to Full Service Customers.*

Income Assistance Credit: *$(7.50)* *per customer per month*

This credit shall not be taken in conjunction with a credit for the Senior Citizen Service Provision (RSC).

Senior Citizen Service Provision (RSC):

When service is supplied to the Principal Residence Customer who is 65 years of age or older and head of household, a credit shall be applied during all billing months.

The monthly credit for the residential Senior Citizen Service Provision shall be applied as follows:

Delivery Charges: *These charges are applicable to Full Service Customers.*

Senior Citizen Credit: *$(3.75)* *per customer per month*

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

Residential Plug-In Electric Vehicle Only Credit (REV):

When service is supplied for Level 2 Charging of a separately metered electric vehicle, a credit shall be applied during all billing months. Electric usage for the household will be billed under the Residential Summer On-Peak Basic Rate or the Residential Smart Hours Rate.

"Level 2 Charging" is defined as voltage connection of either 240 volts or 208 volts and a maximum load of 32 amperes or 7.7 kVA at 240 volts or 6.7 kVA at 208 volts.

Vehicles shall be registered and operable on public highways in the State of Michigan to qualify for this credit. Low-speed electric vehicles including golf carts are not eligible for this credit even if licensed to operate on public streets. The customer may be required to provide proof of registration of the electric vehicle to qualify for this credit.

Delivery Charges: *These charges are applicable to Full Service Customers.*

Residential Plug-In Electric Vehicle Only Credit: *$(7.50) per customer per month*

(Continued on Sheet No. D-17.20)

RESIDENTIAL NIGHTTIME SAVERS RATE

(Continued From Sheet No. D-17.10)

Monthly Rate: (Contd)

Peak Power Savers:

Customers can elect to participate in the Air Conditioning Peak Cycling Program and the Peak Reward Program as described in this tariff. When a customer participates in both programs, the customer's incremental energy savings earned under the Peak Reward is compared to the Peak Power Savers – Air Conditioner Peak Cycling Program Credit. The greater of the two credits will be applied to the customer's invoice for that billing month Both credits will not apply in a single billing month. Customers participating in the Peak Rewards Program cannot participate in the Critical Peak Price Program.

Air Conditioner Peak Cycling Program – (Available on a Date to be Announced by the Company):

A customer in a single family residence who is taking service from the Company may be eligible to participate in the Company's voluntary Peak Power Savers – Air Conditioner Peak Cycling Program for load management of eligible electric central air conditioning, central heat pump, or other qualifying electric equipment. Customer eligibility to participate in this program is determined solely by the Company. The Company will accept a customer's central air conditioning, central heat pump, and other qualifying electric equipment under this program only if it has the capability to be controlled by the Company. Load Management of a customer's swimming pool pump is permitted under this program only if the customer is allowing Load Management of their air conditioner or heat pump unit. The Company will install the required equipment at the customer's premises which will allow Load Management upon signal from the Company. Such equipment shall be furnished, installed, maintained and owned by the Company at the Company's expense. Equipment installations must conform to the Company's specifications.

The Company reserves the right to specify the term or duration of the program. The customer's enrollment shall be terminated if the voluntary program ceases, if the customer tampers with the control switch or the Company's equipment or any reasons as provided for in Rule C1.3, Use of Service.

Load Management may occur any day of the week including weekends between the hours of 7:00 AM and 8:00 PM for no more than an eight hour period in any one day. Load Management may be implemented for, but not limited to, maintaining system integrity, making an emergency purchase, economic reasons, or when there is insufficient system generation available to meet anticipated system load. Load Management may only occur outside of the hours of 7:00 AM and 8:00 PM during a declared emergency event as directed by MISO.

The Customer may contact the Company to request to override a Load Management event for one Load Management event during the June through September months in any one calendar year for the balance of the hours left in that Load Management event with no penalty. The request shall be granted at the discretion of the Company. If the override request was granted by the Company and the customer requests and is granted any additional overrides in the same calendar year, the Peak Power Savers – Air Conditioner Peak Cycling Credit may be forfeited for that billing month.

Rule C1.1 Character of Service, Rule C3 Emergency Electrical Procedures and other rules and regulations contained in the Company's Electric Rate Book apply to customers taking service under this Peak Power Savers – Air Conditioner Peak Cycling Program.

The monthly credit for the Peak Power Savers Program shall be applied as follows:

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

Peak Power Savers – Air Conditioner Peak Cycling Credit:	*\$(8.00)*	*per customer per month during the billing months of June-September*

Peak Reward – (Available on a Date to be Announced by the Company):

Participating customers are able to manage electric costs by reducing load during critical peak events. The Company may call up to fourteen critical peak events between June 1 and September 30. Customers will be notified by 11:59 PM the day before a critical peak event is expected to occur. Receipt of such notice is the responsibility of the participating customer. Customers must have a transmitting meter to participate in Peak Power Savers.

During a critical peak event, customers on will be credited the Peak Reward per kWh of incremental energy reductions.

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

Peak Reward	*\$(0.95)*	*per kWh of incremental energy reduction during a critical peak event between June 1 and September 30*

***Critical Peak Price** – (Available on a Date to be Announced by the Company)*

Participating customers are able to manage electric costs by shifting load during critical peak events to a lower cost pricing period. The Company may call up to fourteen critical peak events between June 1 and September 30. Customers will be notified by 11:59 PM the day before a critical peak event is expected to occur. Receipt of such *notice is the responsibility of the participating customer. Customers must have a transmitting meter to participate in Peak Power Savers.*

During a critical peak event, customers on will be charged the Critical Peak Price per kWh consumed during the critical peak event.

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

Critical Peak Price	*$0.95*	*per kWh of energy consumed during a critical peak event between June 1 and September 30*
Capacity Discount	*$(0.0XXXXX)*	*per kWh for Off-Peak kWh between June 1 and September 30*

(Continued on Sheet No. D-17.30)

RESIDENTIAL NIGHTTIME SAVERS RATE

(Continued From Sheet No. D-17.20)

Monthly Rate: (Contd)

Self-Generation Provision (SG):

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

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

Energy delivered to the Company shall be alternating current, 60-hertz, single-phase or three-phase (as governed by Rule B8., Electric Interconnection and Net Metering Standards) Secondary Voltage or Primary Voltage service. The Company will determine the particular nature of the voltage in each case.

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

Sales of Self-Generated Energy to the Company:

A customer who meets the Federal Energy Regulatory Commission's (FERC) criteria for a Qualifying Facility may elect to sell energy to the Company. The Company has the right to refuse to contract for the purchase of energy. Sales of energy to the Company under this provision shall require a written contract with a minimum term of one year.

Where the customer elects to sell energy to the Company, an Interval Data Meter (IDM) or other applicable meter is required for their generator. Meter reading will be accomplished electronically through telecommunication links or other electronic data methods able to provide the Company with the metering data / billing determinants necessary for billing purposes.

Administrative Cost Charge: *$0.0010 per kWh purchased for generation installations with a capacity of 550 kW or less.*

Energy Purchase:

An energy purchase by the Company shall be bought at the Midcontinent Independent System Operator's, Inc. (MISO) real-time Locational Marginal Price (LMP) for the Company's load node (designated as "CONS.CETR" as of the date of this Rate Schedule). The Company may discontinue purchases during system emergencies, maintenance and other operational circumstances.

(Continued on Sheet No. D-17.40)

RESIDENTIAL NIGHTTIME SAVERS RATE

(Continued From Sheet No. D-17.30)

Monthly Rate: (Contd)

Green Generation Program:

Customer contracts for participation in the Green Generation Program shall be available to any eligible customer as described in Rule C10.2, Green Generation Program.

A customer who participates in the Green Generation Program is subject to the provisions contained in Rule C10.2, Green Generation Program.

General Terms:

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

Minimum Charge:

The System Access Charge included in the rate, adjusted for qualified service provision credit and any applicable non-consumption based surcharges.

Due Date and Late Payment Charge:

The due date of the customer's bill shall be 21 days from the date of transmittal. A late payment charge of 2%, not compounded, of the portion of the bill, net of taxes, shall be assessed to any bill that is delinquent. A customer who participates in the Winter Protection Plan or who is 65 years of age or older and who has notified the Company the customer is 65 years of age or older, shall be exempt from a late payment charge as described in Rule B2., Consumer Standards and Billing Practices for Electric and Natural Gas Service, R 460.125, Late payment charges.

Schedule of Hours:

The following schedule shall apply Monday through Friday including weekday holidays.

Summer: June 1 through September 30
Winter: October 1 through May 31

(1)	*Super Off-Peak Hours:*	*11:00 PM to 6:00 AM*
(2)	*Off-Peak Hours:*	*6:00 AM to 2:00 PM and 7:00 PM to 11:00 PM*
(3)	*On-Peak Hours:*	*2:00 PM to 7:00 PM*

Saturday and Sunday are Super Off-Peak.

Term and Form of Contract:

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

GENERAL SERVICE SECONDARY RATE GS

Availability:

Subject to any restrictions, this rate is available to any general use customer, political subdivision or agency of the State of Michigan, either acting separately or in combinations permitted under the laws of this state, desiring Secondary Voltage service for any of the following: (i) standard secondary service, (ii) public potable water pumping and/or waste water system(s), or (iii) resale purposes. This rate is also available for service to any Primary Rate Customer where the Company elects to provide one transformation from the available Primary Voltage to another available Primary Voltage desired by the customer.

This rate is not available for: (i) private family dwellings, (ii) lighting service except for private streets, mobile home parks or service to temporary lighting installations, (iii) heating water for industrial processing, (iv) resale for lighting service, or (v) new or expanded service for resale to residential customers. Unmetered Billboard Service is not available to Retail Open Access service.

Nature of Service:

Service under this rate shall be alternating current, 60-Hertz, single-phase or three-phase (at the Company's option) Secondary Voltage service. The Company will determine the particular nature of the voltage in each case.

Three-phase, 3-wire service requires that the customer furnishes all transformation facilities required for single-phase load and so arranges the load as to avoid excessive unbalance of the three-phase load. When the service is single-phase, or 4-wire, three-phase, the single-phase individual motor capacity shall not exceed 3 hp, nor the total single-phase motor capacity of 10 hp, without the specific consent of the Company.

Where the Company elects to measure the service on the Primary side of the transformers, 3% shall be deducted for billing purposes from the energy measurements thus made. Where the Company elected to provide a Primary Rate Customer one transformation from the available Primary Voltage to another available Primary Voltage desired by the customer, 3% shall not be deducted for billing purposes from the energy measurements thus made.

Monthly Rate:

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

Energy Charge:

Non-Capacity	Capacity	Total	
$~~0.064518~~ *0.062210*	$~~0.032361~~ *0.034294*	$~~0.096879~~ *0.096504*	per kWh for all kWh during the billing months of June-September
$~~0.061907~~ *0.061580*	$~~0.031051~~ *0.033947*	$~~0.092958~~ *0.095527*	per kWh for all kWh during the billing months of October-May

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-4.00.

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

System Access Charge:	$20.00	per customer per month
Distribution Charge:	$~~0.042765~~ *0.042472*	per kWh for all kWh

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-3.10 and the Power Plant Securitization Charges shown on Sheet No. D-5.10.

Billboard Service Provision:

Monthly kWh shall be determined by multiplying the total connected load in kW (including the lamps, ballasts, transformers, amplifiers, and control devices) times 730 hours. The kWh for cyclical devices shall be adjusted for the average number of hours used.

(Continued on Sheet No. D-19.00)

GENERAL SERVICE SECONDARY RATE GS

(Continued From Sheet No. D-18.00)

Monthly Rate: (Contd)

Resale Service Provision:

Subject to any restrictions, this provision is available to customers desiring Secondary Voltage service for resale purposes in accordance with Rule C4.4, Resale.

Educational Institution Service Provision (GEI):

When service is supplied to a school, college or university, a credit shall be applied during all billing months. As used in this provision, “school” shall mean buildings, facilities, playing fields, or property directly or indirectly used for school purposes for children in grades kindergarten through twelve, when provided by a public or nonpublic school. School does not include instruction provided in a private residence or proprietary trade, vocational, training, or occupational school. “College” or “University” shall mean buildings located on the same campus and used to impart instruction, including all adjacent and appurtenant buildings owned by the same customer which are located on the same campus and which constitute an integral part of such college or university facilities.

The monthly credit for the Educational Institution Service Provision shall be applied as follows:

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

Education Institution Credit: $*(0.000748)* ~~(0.000708)~~ per kWh for all kWh

Customers on this provision shall require a written contract, with a minimum term of one year, and shall be evaluated annually to determine whether or not the accounts shall remain on the service provision.

Self-Generation Provision (SG):

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

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

Energy delivered to the Company shall be alternating current, 60-hertz, single-phase or three-phase (as governed by Rule B8., Electric Interconnection and Net Metering Standards) Secondary Voltage or Primary Voltage service. The Company will determine the particular nature of the voltage in each case.

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

Sales of Self-Generated Energy to the Company:

A customer who meets the Federal Energy Regulatory Commission’s (FERC) criteria for a Qualifying Facility may elect to sell energy to the Company. The Company has the right to refuse to contract for the purchase of energy. Sales of energy to the Company under this provision shall require a written contract with a minimum term of one year.

Where the customer elects to sell energy to the Company, an Interval Data Meter (IDM) or other applicable meter is required for their generator. Meter reading will be accomplished electronically through telecommunication links or other electronic data methods able to provide the Company with the metering data / billing determinants necessary for billing purposes.

(Continued on Sheet No. D-19.10)

GENERAL SERVICE SECONDARY RATE GS

(Continued From Sheet No. D-19.00)

Monthly Rate: (Contd)

Administrative Cost Charge:

$0.0010 per kWh purchased for generation installations with a capacity of ~~100~~ *550* kW or less.

Energy Purchase:

An energy purchase by the Company shall be bought at the Midcontinent Independent System Operator's, Inc. (MISO) real-time Locational Marginal Price (LMP) for the Company's load node (designated as "CONS.CETR" as of the date of this Rate Schedule). The Company may discontinue purchases during system emergencies, maintenance and other operational circumstances.

Net Metering Program:

The Net Metering Program is available to any eligible customer as described in Rule C11, Net Metering Program, who desires to generate a portion or all of their own retail electricity requirements using a Renewable Energy Resource as defined in Rule C11.B, Net Metering Definitions.

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

Green Generation Program:

Customer contracts for participation in the Green Generation Program shall be available to any eligible customer as described in Rule C10.2, Green Generation Program.

A customer who participates in the Green Generation Program is subject to the provision contained in Rule C10.2, Green Generation Program.

Non-Transmitting Meter Provision:

A customer who chooses a non-transmitting meter is subject to the provisions contained in Rule C5.5, Non-Transmitting Meter Provision.

General Terms:

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

Minimum Charge:

The System Access Charge included in the rate and any applicable non-consumption based surcharges. Special Minimum Charges shall be billed in accordance with Rule C15., Special Minimum Charges.

Due Date and Late Payment Charge:

The due date of the customer bill shall be 21 days from the date of mailing. A late payment charge of 2% of the unpaid balance, net of taxes, shall be assessed to any bill which is not paid on or before the due date shown thereon.

Term and Form of Contract:

Service under this rate shall not require a written contract except for: (i) resale service, (ii) service under the Green Generation Program, (iii) for Special Minimum Charges, (iv) service for lighting or where mobile home parks are involved, (v) service under the Educational Institution Service Provision, (vi) service under the Net Metering Program, or (vii) at the option of the Company. If a contract is deemed necessary by the Company, the appropriate contract form shall be used and the contract shall require a minimum term of one year.

GENERAL SERVICE SECONDARY TIME-OF-USE RATE GSTU

Availability:

Subject to any restrictions, General Service Secondary Time-of-Use Rate GSTU is available to any Full Service Customer taking service at the Company's Secondary Voltage level with advanced metering infrastructure and supporting critical systems.

This rate is not available for: (i) private family dwellings, (ii) lighting service except for private streets, mobile home parks or service to temporary lighting installations, (iii) heating water for industrial processing, (iv) resale for lighting service, or (v) new or expanded service for resale to residential customers.

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

Nature of Service:

Service under this rate shall be alternating current, 60-Hertz, single-phase or three-phase (at the Company's option) Secondary Voltage service. The Company will determine the particular nature of the voltage in each case.

Three-phase, 3-wire service requires that the customer furnishes all transformation facilities required for single-phase load and so arranges the load as to avoid excessive unbalance of the three-phase load. When the service is single-phase, or 4-wire, three-phase, the single-phase individual motor capacity shall not exceed 3 hp, nor the total single-phase motor capacity of 10 hp, without the specific consent of the Company.

Where the Company elects to measure the service on the Primary side of the transformers, 3% shall be deducted for billing purposes from the energy measurements thus made. Where the Company elected to provide a Primary Rate Customer one transformation from the available Primary Voltage to another available Primary Voltage desired by the customer, 3% shall not be deducted for billing purposes from the energy measurements thus made.

Monthly Rate:

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

Energy Charge:

	Non-Capacity	Capacity	Total	
Off-Peak - Summer	$~~0.059509~~ *0.055495*	$~~0.029848~~ *0.030592*	$~~0.089357~~ *0.086087*	per kWh for all Off-Peak kWh during the billing months of June - September
Mid-Peak - Summer	$~~0.090026~~ *0.086391*	$~~0.045155~~ *0.047624*	$~~0.135181~~ *0.134015*	per kWh for all Mid-Peak kWh during the billing months of June - September
On-Peak - Summer	$~~0.112717~~ *0.109946*	$~~0.056536~~ *0.060609*	$~~0.169253~~ *0.170555*	per kWh for all On-Peak kWh during the billing months of June - September
Off-Peak - Winter	$~~0.050823~~ *0.050720*	$~~0.025492~~ *0.027960*	$~~0.076315~~ *0.078680*	per kWh for all Off-Peak kWh during the billing months of October - May
On-Peak - Winter	$~~0.057191~~ *0.057913*	$~~0.028686~~ *0.031925*	$~~0.085877~~ *0.089838*	per kWh for all On-Peak kWh during the billing months of October - May

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-4.00.

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

System Access Charge:	$20.00	per customer per month
Distribution Charge:	$~~0.042765~~ *0.042472*	per kWh for all kWh for a Full Service Customer

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-3.10 and the Power Plant Securitization Charges shown on Sheet No. D-5.10.

(Continued on Sheet No. D-21.20)

GENERAL SERVICE SECONDARY TIME-OF-USE RATE GSTU

(Continued From Sheet No. D-21.10)

Monthly Rate: (Contd)

Schedule of Hours:

The following schedule shall apply Monday through Friday (except holidays designated by the Company). Weekends and holidays are off-peak. Holidays designated by the Company include: New Year' Day – January 1, Memorial Day – Last Monday in May, Independence Day – July 4, Labor Day – First Monday in September, Thanksgiving Day – Fourth Thursday in November, and Christmas Day – December 25. Whenever January 1, July 4, or December 25 falls on Sunday, extended holiday periods such as Monday, January 2, Monday, July 5 and Monday, December 26 shall not be considered as holidays for application of off-peak hours.

Summer Billing Months of June through September:

(1) Off-Peak Hours: 12:00 AM to 7:00 AM and 11:00 PM to 12:00 AM
(2) Mid-Peak Hours: 7:00 AM to 2:00 PM and 6:00 PM to 11:00 PM
(3) On-Peak Hours: 2:00 PM to 6:00 PM

Winter Billing Months of January through May and October through December:

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

Resale Service Provision:

Subject to any restrictions, this provision is available to customers desiring Secondary Voltage service for resale purposes in accordance with Rule C4.4, Resale.

Educational Institution Service Provision (GEI):

When service is supplied to a school, college or university, a credit shall be applied during all billing months. As used in this provision, "school" shall mean buildings, facilities, playing fields, or property directly or indirectly used for school purposes for children in grades kindergarten through twelve, when provided by a public or nonpublic school. School does not include instruction provided in a private residence or proprietary trade, vocational, training, or occupational school. "College" or "University" shall mean buildings located on the same campus and used to impart instruction, including all adjacent and appurtenant buildings owned by the same customer which are located on the same campus and which constitute an integral part of such college or university facilities.

The monthly credit for the Educational Institution Service Provision shall be applied as follows:

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

Education Institution Credit: $(~~0.000708~~ *0.000748*) per kWh for all kWh

Customers on this provision shall require a written contract, with a minimum term of one year, and shall be evaluated annually to determine whether or not the accounts shall remain on the service provision.

Self-Generation Provision (SG):

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

All facilities must meet the Parallel Operation Requirements set forth in Rule C 1.6 B. The Company shall own, operate and maintain all metering and auxiliary devices (including telecommunication links) at the customer's expense. Meters furnished, installed and maintained by the Company shall meter generation equipment for customers that sell energy to the Company. No refund shall be made for any customer contribution required.

Energy delivered to the Company shall be alternating current, 60-hertz, single-phase or three-phase (as governed by Rule B8., Electric Interconnection and Net Metering Standards) Secondary Voltage or Primary Voltage service. The Company will determine the particular nature of the voltage in each case.

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

(Continued on Sheet No. D-21.30)

GENERAL SERVICE SECONDARY TIME-OF-USE RATE GSTU

(Continued From Sheet No. D-21.20)

Monthly Rate: (Contd)

Sales of Self-Generated Energy to the Company:

A customer who meets the Federal Energy Regulatory Commission's (FERC) criteria for a Qualifying Facility may elect to sell energy to the Company. The Company has the right to refuse to contract for the purchase of energy. Sales of energy to the Company under this provision shall require a written contract with a minimum term of one year.

Where the customer elects to sell energy to the Company, an Interval Data Meter (IDM) or other applicable meter is required for their generator. Meter reading will be accomplished electronically through telecommunication links or other electronic data methods able to provide the Company with the metering data/ billing determinants necessary for billing purposes.

Administrative Cost Charge:

$0.0010 per kWh purchased for generation installations with a capacity of ~~100~~ *550* kW or less.

Energy Purchase:

An energy purchase by the Company shall be bought at the Midcontinent Independent System Operator's, Inc. (MISO) real-time Locational Marginal Price (LMP) for the Company's load node (designated as "CONS.CETR" as of the date of this Rate Schedule). The Company may discontinue purchases during system emergencies, maintenance and other operational circumstances.

Green Generation Program:

Customer contracts for participation in the Green Generation Program shall be available to any eligible customer as described in Rule C10.2, Green Generation Program.

A customer who participates in the Green Generation Program is subject to the provision contained in Rule C 10.2, Green Generation Program.

General Terms:

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

Minimum Charge:

The System Access Charge included in the rate and any applicable non-consumption based surcharges. Special Minimum Charges shall be billed in accordance with Rule C15., Special Minimum Charges.

Due Date and Late Payment Charge:

The due date of the customer bill shall be 21 days from the date of mailing. A late payment charge of 2% of the unpaid balance, net of taxes, shall be assessed to any bill which is not paid on or before the due date shown thereon.

Term and Form of Contract:

Service under this rate shall not require a written contract except for: (i) resale service, (ii) service under the Green Generation Program, (iii) for Special Minimum Charges, (iv) service for lighting or where mobile home parks are involved, (v) service under the Educational Institution Service Provision, or (vi) at the option of the Company. If a contract is deemed necessary by the Company, the appropriate contract form shall be used and the contract shall require a minimum term of one year.

GENERAL SERVICE SECONDARY DEMAND RATE GSD

Availability:

Subject to any restrictions, this rate is available to any customer desiring Secondary Voltage service, either for general use or resale purposes, where the Peak Demand is 5 kW or more. This rate is also available for service to any Primary Rate Customer where the Company elects to provide one transformation from the available Primary Voltage to another available Primary Voltage desired by the customer.

This rate is not available for: (i) private family dwellings, (ii) lighting service, (iii) resale for lighting service, or (iv) new or expanded service for resale to residential customers.

Nature of Service:

Service under this rate shall be alternating current, 60-Hertz, single-phase or three-phase (at the Company's option) Secondary Voltage service. The Company will determine the particular nature of the voltage in each case.

Three-phase, 3-wire service requires that the customer furnishes all transformation facilities required for single-phase load and so arranges the load as to avoid excessive unbalance of the three-phase load. When the service is single-phase, or 4-wire, three-phase, the single-phase individual motor capacity shall not exceed 3 hp, nor the total single-phase motor capacity of 10 hp, without the specific consent of the Company.

Where the Company elects to measure the service on the Primary side of the transformers, 3% shall be deducted for billing purposes from the demand and energy measurements thus made. Where the Company elected to provide a Primary Rate Customer one transformation from the available Primary Voltage to another available Primary Voltage desired by the customer, 3% shall not be deducted for billing purposes from the energy measurements thus made.

Monthly Rate:

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

~~Capacity~~ *Peak Demand* Charge:

Non-Capacity	*Capacity*	*Total*	
$8.10	$~~12.30~~ *13.04*	*$21.14*	per kW for all kW of Peak Demand during the billing months of June-September
$6.10	$~~10.30~~ *11.04*	*$17.14*	per kW for all kW of Peak Demand during the billing months of October-May

Energy Charge:

Non-Capacity	
$~~0.066286~~ *0.043298*	per kWh for all kWh during the billing months of June-September.
$~~0.061142~~ *0.040994*	per kWh for all kWh during the billing months of October-May.

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-4.00.

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

System Access Charge:	$30.00	per customer per month
Capacity Charge:	$1.15	per kW for all kW of Peak Demand
Distribution Charge:	$~~0.035219~~ *0.029722*	per kWh for all kWh

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-3.10 and the Power Plant Securitization Charges shown on Sheet No. D-5.10.

(Continued on Sheet No. D-23.00)

GENERAL SERVICE SECONDARY DEMAND RATE GSD

(Continued From Sheet No. D-23.00)

Monthly Rate: (Contd)

Educational Institution Service Provision (GEI):

When service is supplied to a school, college or university, a credit shall be applied during all billing months. As used in this provision, "school" shall mean buildings, facilities, playing fields, or property directly or indirectly used for school purposes for children in grades kindergarten through twelve, when provided by a public or nonpublic school. School does not include instruction provided in a private residence or proprietary trade, vocational, training, or occupational school. "College" or "University" shall mean buildings located on the same campus and used to impart instruction, including all adjacent and appurtenant buildings owned by the same customer which are located on the same campus and which constitute an integral part of such college or university facilities.

The monthly credit for the Educational Institution Service Provision shall be applied as follows:

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

Education Institution Credit: $(~~0.000618~~ *0.000616*) per kWh for all kWh

Customers on this provision shall require a written contract, with a minimum term of one year, and shall be evaluated annually to determine whether or not the accounts shall remain on the service provision.

Self-Generation Provision (SG):

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

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

Energy delivered to the Company shall be alternating current, 60-hertz, single-phase or three-phase (as governed by Rule B8., Electric Interconnection and Net Metering Standards) Secondary Voltage or Primary Voltage service. The Company will determine the particular nature of the voltage in each case.

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

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

Sales of Self-Generated Energy to the Company:

A customer who meets the Federal Energy Regulatory Commission's (FERC) criteria for a Qualifying Facility may elect to sell energy to the Company. The Company has the right to refuse to contract for the purchase of energy. Sales of energy to the Company under this provision shall require a written contract with a minimum term of one year.

Where the customer elects to sell energy to the Company, an Interval Data Meter (IDM) or other applicable meter is required for their generator. Meter reading will be accomplished electronically through telecommunication links or other electronic data methods able to provide the Company with the metering data / billing determinants necessary for billing purposes.

Administrative Cost Charge:

$0.0010 per kWh purchased for generation installations with a capacity of ~~100~~ *550* kW or less.

(Continued on Sheet No. D-24.10)

GENERAL SERVICE PRIMARY RATE GP

Availability:

Subject to any restrictions, this rate is available to any customer, political subdivision or agency of the State of Michigan, either acting separately or in combinations permitted under the laws of this state, desiring Primary Voltage service for general use or for public potable water pumping and/or waste water system(s).

This rate is available to existing Full Service Customers with an electric generating facility interconnected at a primary voltage level utilizing General Service Primary Rate GP for standby service on or before June 7, 2012. The amount of retail usage shall be determined on an hourly basis. Customers with a generating installation are required to have an Interval Data Meter.

This rate is not available to a Primary Rate Customer where the Company elects to provide one transformation from the available Primary Voltage to another available Primary Voltage desired by the customer.

This rate is not available for lighting service, except for temporary service for lighting installations.

Nature of Service:

Service under this rate shall be alternating current, 60-Hertz, single-phase or three-phase (at the Company's option) Primary Voltage service. The Company will determine the particular nature of the voltage in each case.

Where service is supplied at a nominal voltage of 25,000 Volts or less, the customer shall furnish, install and maintain all necessary transforming, controlling and protective equipment.

Where the Company elects to measure the service at a nominal voltage above 25,000 Volts, 1% shall be deducted for billing purposes, from the energy measurements thus made.

Where the Company elects to measure the service at a nominal voltage of less than 2,400 Volts, 3% shall be added for billing purposes, to the energy measurements thus made.

Monthly Rate:

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

Charges for Customer Voltage Level 3 (CVL 3)

Energy Charge:

Non-Capacity	Capacity	Total	
$~~0.059274~~	$~~0.041771~~	$~~0.101045~~	per kWh for all kWh during the billing months of June-September
0.058898	*0.047432*	*0.106330*	
$~~0.057187~~	$~~0.040392~~	$~~0.097579~~	per kWh for all kWh during the billing months of October-May
0.058404	*0.047054*	*0.105458*	

Charges for Customer Voltage Level 2 (CVL 2)

Energy Charge:

Non-Capacity	Capacity	Total	
$~~0.053574~~	$~~0.036071~~	$~~0.089645~~	per kWh for all kWh during the billing months of June-September
0.053957	*0.042491*	*0.096448*	
$~~0.051487~~	$~~0.034692~~	$~~0.086179~~	per kWh for all kWh during the billing months of October-May
0.053463	*0.042113*	*0.095576*	

Charges for Customer Voltage Level 1 (CVL 1)

Energy Charge:

Non-Capacity	Capacity	Total	
$~~0.051574~~	$~~0.034071~~	$~~0.085645~~	per kWh for all kWh during the billing months of June-September
0.048787	*0.037321*	*0.086108*	
$~~0.049487~~	$~~0.032692~~	$~~0.082179~~	per kWh for all kWh during the billing months of October-May
0.048293	*0.036943*	*0.085236*	

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-4.00.

(Continued on Sheet No. D-27.10)

GENERAL SERVICE PRIMARY RATE GP

(Continued From Sheet No. D-27.00)

Monthly Rate (Contd)

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

System Access Charge: $100.00 per customer per month

Charges for Customer Voltage Level 3 (CVL 3)

Distribution Charge: $~~0.017248~~ *0.013386* per kWh for all kWh

Charges for Customer Voltage Level 2 (CVL 2)

Distribution Charge: $~~0.010773~~ *0.007723* per kWh for all kWh

Charges for Customer Voltage Level 1 (CVL 1)

Distribution Charge: $~~0.007882~~ *0.005733* per kWh for all kWh

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-3.10 and the Power Plant Securitization Charges shown on Sheet No. D-5.10.

Adjustment for Power Factor

This rate requires a determination of the average Power Factor maintained by the customer during the billing period. Such average Power Factor shall be determined through metering of lagging Kilovar-hours and Kilowatt-hours during the billing period. The calculated ratio of lagging Kilovar-hours to Kilowatt-hours shall then be converted to the average Power Factor for the billing period by using the appropriate conversion factor. Whenever the average Power Factor during the billing period is above .899 or below .850, the customer bill shall be adjusted as follows:

(a) If the average Power Factor during the billing period is .900 or higher, a 0.50% credit will be applied to all metered-based charges, excluding surcharges. This credit shall not in any case be used to reduce the prescribed Minimum Charge.

(b) If the average Power Factor during the billing period is less than .850, a penalty will be applied to all metered-based charges, excluding surcharges, in accordance with the following table:

Power Factor	**Penalty**
0.800 to 0.849	0.50%
0.750 to 0.799	1.00%
0.700 to 0.749	2.00%
Below 0.700	3% first 2 months

(c) A Power Factor less than 0.700 is not permitted and necessary corrective equipment must be installed by the customer. A 15% penalty will be applied to any metered-based charges, excluding surcharges, after two consecutive months below 0.700 Power Factor and will continue as long as the Power Factor remains below 0.700. Once the customer's Power Factor exceeds 0.700, it is necessary to complete two consecutive months below 0.700 before the 15% penalty applies again.

Resale Service Provision

Subject to any restrictions, this provision is available to customers desiring Primary Voltage service for resale purposes in accordance with Rule C4.4, Resale.

(Continued on Sheet No. D-28.00)

GENERAL SERVICE PRIMARY RATE GP

(Continued From Sheet No. D-27.10)

Monthly Rate (Contd)

Substation Ownership Credit

Where service is supplied at a nominal voltage of more than 25,000 volts, and the customer provides all of the necessary transforming, controlling and protective equipment for all of the service there shall be deducted from the bill a monthly credit.

The monthly credit for the substation ownership shall be applied as follows:

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

Substation Ownership Credit: $ (~~0.000394~~ *0.000287*) per kWh for all kWh

For those customers served by more than one substation where one or more of the substations is owned by the customer, the credit will be applied to the customer's coincident Maximum Demand for those substations owned by the customer. This credit shall not operate to reduce the customer's billing below the prescribed minimum charges included in the rate. The credit shall be based on the kW after the 1% deduction or 3% addition has been applied to the metered kWh.

Educational Institution Service Provision (GEI)

When service is supplied to a school, college or university, a credit shall be applied during all billing months. As used in this provision, "school" shall mean buildings, facilities, playing fields, or property directly or indirectly used for school purposes for children in grades kindergarten through twelve, when provided by a public or nonpublic school. School does not include instruction provided in a private residence or proprietary trade, vocational, training, or occupational school. "College" or "University" shall mean buildings located on the same campus and used to impart instruction, including all adjacent and appurtenant buildings owned by the same customer which are located on the same campus and which constitute an integral part of such college or university facilities.

The monthly credit for the Educational Institution Service Provision shall be applied as follows:

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

Educational Institution Credit: $(~~0.000530~~ *0.000571*) per kWh for all kWh

Customers on this provision shall require a written contract, with a minimum term of one year, and shall be evaluated annually to determine whether or not the accounts shall remain on the service provision.

Self-Generation Provision (SG):

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

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

Energy delivered to the Company shall be alternating current, 60-hertz, single-phase or three-phase (as governed by Rule B8., Electric Interconnection and Net Metering Standards) Secondary Voltage or Primary Voltage service. The Company will determine the particular nature of the voltage in each case.

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

(Continued on Sheet No. D-29.00)

GENERAL SERVICE PRIMARY RATE GP

(Continued From Sheet No. D-28.00)

Monthly Rate (Contd)

Self-Generation Provision (SG) (Contd):

Sales of Self-Generated Energy to the Company:

A customer who meets the Federal Energy Regulatory Commission's (FERC) criteria for a Qualifying Facility may elect to sell energy to the Company. The Company has the right to refuse to contract for the purchase of energy. Sales of energy to the Company under this provision shall require a written contract with a minimum term of one year.

Where the customer elects to sell energy to the Company, an Interval Data Meter (IDM) or other applicable meter is required for their generator. Meter reading will be accomplished electronically through telecommunication links or other electronic data methods able to provide the Company with the metering data / billing determinants necessary for billing purposes.

Administrative Cost Charge: $0.0010 per kWh purchased for generation installations with a capacity of ~~100~~ *550* kW or less.

Energy Purchase:

An energy purchase by the Company shall be bought at the Midcontinent Independent System Operator's, Inc. (MISO) real-time Locational Marginal Price (LMP) for the Company's load node (designated as "CONS.CETR" as of the date of this Rate Schedule). The Company may discontinue purchases during system emergencies, maintenance and other operational circumstances.

Net Metering Program:

The Net Metering Program is available to any eligible customer as described in Rule C11., Net Metering Program, who desires to generate a portion or all of their own retail electricity requirements using a Renewable Energy Resource as defined in Rule C11.B, Net Metering Definitions.

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

Green Generation Program:

Customer contracts for participation in the Green Generation Program shall be available to any eligible customer as described in Rule C10.2, Green Generation Program.

A customer who participates in the Green Generation Program is subject to the provisions contained in Rule C10.2, Green Generation Program.

General Terms:

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

Minimum Charge:

The System Access charge included in the rate and any applicable non-consumption based surcharges.

Due Date and Late Payment Charge

The due date of the customer bill shall be 21 days from the date of mailing. A late payment charge of 2% of the unpaid balance, net of taxes, shall be assessed to any bill which is not paid on or before the due date shown thereon.

Term and Form of Contract

For customers with monthly demands of 300 kW or more, all service under this rate shall require a written contract with a minimum term of one year.

For customers with monthly demands of less than 300 kW, service under this rate shall not require a written contract except for: (i) service under the Green Generation Program, (ii) service under the Educational Institution provision, (iii) service under the Resale Service Provision, (iv) service under the Net Metering Program, or (v) at the option of the Company. If a contract is deemed necessary by the Company, the appropriate contract form shall be used and the contract shall require a minimum term of one year.

A new contract will not be required for existing customers who increase their demand requirements after initiating service, unless new or additional facilities are required or service provisions deem it necessary.

LARGE GENERAL SERVICE PRIMARY DEMAND RATE GPD

Availability

Subject to any restrictions, this rate is available to any customer desiring Primary Voltage service, either for general use or resale purposes, where the On-Peak Billing Demand is 25 kW or more. This rate is also available to any political subdivision or agency of the State of Michigan, either acting separately or in combinations permitted under the laws of this state, for Primary Voltage service for potable water pumping and/or waste water system(s).

This rate is not available to a Primary Rate Customer where the Company elects to provide one transformation from the available Primary Voltage to another available Primary Voltage desired by the customer.

This rate is also not available for lighting service, for resale for lighting service, or for new or expanded service for resale to residential customers.

Nature of Service

Service under this rate shall be alternating current, 60-Hertz, single-phase or three-phase (at the Company's option) Primary Voltage service. The Company will determine the particular nature of the voltage in each case.

Where service is supplied at a nominal voltage of 25,000 Volts or less, the customer shall furnish, install and maintain all necessary transforming, controlling and protective equipment.

Where the Company elects to measure the service at a nominal voltage above 25,000 Volts, 1% shall be deducted for billing purposes, from the demand and energy measurements thus made.

Where the Company elects to measure the service at a nominal voltage of less than 2,400 Volts, 3% shall be added for billing purposes, to the demand and energy measurements thus made.

Interval Data Meters are required for service under this rate. Meter reading will be accomplished electronically through telecommunication links or other electronic data methods able to provide the Company with the metering data / billing determinants necessary for billing purposes.

Monthly Rate:

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

<u>Charges for Customer Voltage Level 3 (CVL3)</u>

Demand Charge:

Non-Capacity	Capacity	Total	
$~~7.74~~ *10.34*	$~~12.66~~ *14.82*	$~~20.40~~ *25.16*	per kW of On-Peak Billing Demand during the billing months of June-September
$~~7.74~~ *9.34*	$~~11.66~~ *13.82*	$~~19.40~~ *23.16*	per kW of On-Peak Billing Demand during the billing months of October-May

Transmission Charge:

Capacity	
$~~1.84~~ *6.98*	per kW of On-Peak Billing Demand during the billing months of June-September
$~~1.84~~ *6.98*	per kW of On-Peak Billing Demand during the billing months of October-May

Energy Charge:

Non-Capacity	
$~~0.053971~~ *0.042156*	per kWh for all On-Peak kWh during the billing months of June-September
$~~0.038070~~ *0.027322*	per kWh for all Off-Peak kWh during the billing months of June-September
$~~0.044018~~ *0.034413*	per kWh for all On-Peak kWh during the billing months of October-May
$~~0.039974~~ *0.030139*	per kWh for all Off-Peak kWh during the billing months of October-May

(Continued on Sheet No. D-31.05)

Attachment 2
To Settlement Agreement In Case No. U-20134

LARGE GENERAL SERVICE PRIMARY DEMAND RATE GPD

(Continued From Sheet No. D-31.00)

Monthly Rate: (Contd)

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

Charges for Customer Voltage Level 2 (CVL2)

Demand Charge:

Non- Capacity	Capacity	Total	
$~~7.74~~ *9.84*	$~~11.66~~ *14.32*	$~~19.40~~ *24.16*	per kW of On-Peak Billing Demand during the billing months of June-September
$~~7.74~~ *8.84*	$~~10.66~~ *13.32*	$~~18.40~~ *22.16*	per kW of On-Peak Billing Demand during the billing months of October-May

Transmission Charge:

Capacity	
$~~1.84~~ *6.71*	per kW of On-Peak Billing Demand during the billing months of June-September
$~~1.84~~ *6.71*	per kW of On-Peak Billing Demand during the billing months of October-May

Energy Charge:

Non-Capacity	
$~~0.048271~~ *0.034239*	per kWh for all On-Peak kWh during the billing months of June-September
$~~0.032370~~ *0.022191*	per kWh for all Off-Peak kWh during the billing months of June-September
$~~0.038318~~ *0.027950*	per kWh for all On-Peak kWh during the billing months of October-May
$~~0.034274~~ *0.024479*	per kWh for all Off-Peak kWh during the billing months of October-May

Charges for Customer Voltage Level 1 (CVL1)

Demand Charge:

Non-Capacity	Capacity	Total	
$~~7.74~~ *9.34*	$~~10.66~~ *13.82*	$~~18.40~~ *23.16*	per kW of On-Peak Billing Demand during the billing months of June-September
$~~7.74~~ *8.34*	$~~9.66~~ *12.82*	$~~17.40~~ *21.16*	per kW of On-Peak Billing Demand during the billing months of October-May

Transmission Charge:

Capacity	
$~~1.84~~ *6.58*	per kW of On-Peak Billing Demand during the billing months of June-September
$~~1.84~~ *6.58*	per kW of On-Peak Billing Demand during the billing months of October-May

Energy Charge:

Non-Capacity	
$~~0.046271~~ *0.026510*	per kWh for all On-Peak kWh during the billing months of June-September
$~~0.030370~~ *0.017182*	per kWh for all Off-Peak kWh during the billing months of June-September
$~~0.036318~~ *0.021641*	per kWh for all On-Peak kWh during the billing months of October-May
$~~0.032274~~ *0.018953*	per kWh for all Off-Peak kWh during the billing months of October-May

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-4.00.

(Continued on Sheet No. D-31.10)

LARGE GENERAL SERVICE PRIMARY DEMAND RATE GPD

(Continued From Sheet No. D-31.05)

Monthly Rate: (Contd)

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

System Access Charge:	$200.00	per customer per month
Charges for Customer Voltage Level 3 (CVL3)		
Capacity Charge:	$ ~~4.20~~ *3.60*	per kW of Maximum Demand
Charges for Customer Voltage Level 2 (CVL2)		
Capacity Charge:	$ ~~1.85~~ *1.86*	per kW of Maximum Demand
Charges for Customer Voltage Level 1 (CVL1)		
Capacity Charge:	$ ~~0.96~~ *0.91*	per kW of Maximum Demand

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-3.10 and the Power Plant Securitization Charges shown on Sheet No. D-5.10

Adjustment for Power Factor:

This rate requires a determination of the average Power Factor maintained by the customer during the billing period. Such average Power Factor shall be determined through metering of lagging Kilovar-hours and Kilowatt-hours during the billing period. The calculated ratio of lagging Kilovar-hours to Kilowatt-hours shall then be converted to the average Power Factor for the billing period by using the appropriate conversion factor. Whenever the average Power Factor during the billing period is above .899 or below .850, the customer bill shall be adjusted as follows:

(a) If the average Power Factor during the billing period is .900 or higher, a 0.50% credit will be applied to all metered-based charges, excluding surcharges. This credit shall not in any case be used to reduce the prescribed Minimum Charge.

(b) If the average Power Factor during the billing period is less than .850, a penalty will be applied to all metered-based charges, excluding surcharges, in accordance with the following table:

Power Factor	**Penalty**
0.800 to 0.849	0.50%
0.750 to 0.799	1.00%
0.700 to 0.749	2.00%
Below 0.700	3% first 2 months

Adjustment for Power Factor shall not be applied when the On-Peak Billing Demand is based on 60% of the highest On-Peak Billing Demand created during the preceding bill months of June through September or on a Minimum On-Peak Billing Demand.

(c) A Power Factor less than 0.700 is not permitted and necessary corrective equipment must be installed by the customer. A 15% penalty will be applied to any metered-based charges, excluding surcharges, after two consecutive months below 0.700 Power Factor and will continue as long as the Power Factor remains below 0.700. Once the customer's Power Factor exceeds 0.700, it is necessary to complete two consecutive months below 0.700 before the 15% penalty applies again.

(Continued on Sheet No. D-32.00)

LARGE GENERAL SERVICE PRIMARY DEMAND RATE GPD

(Continued From Sheet No. D-31.10)

Monthly Rate (Contd)

Maximum Demand

The Maximum Demand shall be the highest 15-minute demand created during the current month or previous 11 months.

On-Peak Billing Demand

The On-Peak Billing Demand shall be based on the highest on-peak demand created during the billing month, but never less than 60% of the highest on-peak billing demand of the preceding billing months of June through September, nor less than 25 kW.

The On-Peak Billing Demand shall be the Kilowatts (kW) supplied during the 15-minute period of maximum use during on-peak hours, as described in Rule C14., Provisions Governing the Application of On-Peak and Off-Peak Rates.

The Company reserves the right to make special determination of the On-Peak Billing Demand, and/or the Minimum Charge, should the equipment which creates momentary high demands be included in the customer's installation.

Transmission On-Peak Billing Demand

The Transmission On-Peak Billing Demand for each billing month shall be the Kilowatts (kW) supplied during the 15-minute period of maximum use during on-peak hours, as described in Rule C14., Provisions Governing the Application of On-Peak and Off-Peak Rates.

Resale Service Provision

Subject to any restrictions, this provision is available to customers desiring Primary Voltage service for resale purposes in accordance with Rule C4.4, Resale.

Substation Ownership Credit

Where service is supplied at a nominal voltage of more than 25,000 Volts, energy is measured through an Interval Data Meter, and the customer provides all of the necessary transforming, controlling and protective equipment for all of the service there shall be deducted from the bill a monthly credit. For those customers, part of whose load is served through customer-owned equipment, the credit shall be based on the Maximum Demand.

The monthly credit for the substation ownership shall be applied as follows:

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

Charges for Customer Voltage Level 2 (CVL 2)

Substation Ownership Credit: $(~~0.65~~ *0.97*) per kW of Maximum Demand

Charges for Customer Voltage Level 1 (CVL 1)

Substation Ownership Credit: $(~~0.38~~ *0.45*) per kW of Maximum Demand

For those customers served by more than one substation where one or more of the substations is owned by the customer, the credit will be applied to the customer's coincident Maximum Demand for those substations owned by the customer. This credit shall not operate to reduce the customer's billing below the prescribed minimum charges included in the rate. The credit shall be based on the kW after the 1% deduction or 3% addition has been applied to the metered kW.

(Continued on Sheet No. D-33.00)

LARGE GENERAL SERVICE PRIMARY DEMAND RATE GPD

(Continued From Sheet No. D-32.00)

Monthly Rate: (Contd)

Aggregate Peak Demand Service Provision (GAP)

This provision is available to any customer with 7 accounts or more who desire to aggregate their On-Peak Billing Demands for power supply billing purposes. To be eligible, each account must have a minimum average On-Peak Billing Demand of 250 kW and be located within the same billing district. The customer's aggregated accounts shall be billed under the same rate schedule and service provisions. The aggregate maximum capacity of all customers served under this provision shall be limited to 200,000 kW.

This provision commences with service rendered on and after June 20, 2008 and remains in effect until terminated by a Commission Order.

Customers on this provision shall require a written contract, with a minimum term of one year, and shall be evaluated annually to determine whether or not the accounts shall remain on the service provision.

Interval Data Meters are required for service under this provision.

The aggregated accounts shall be summarized for each interval time period registered and a comparison shall be performed to determine the on-peak time at which the summarized value of the aggregated accounts reached a maximum for the billing month. The individual aggregated accounts shall be billed for their corresponding On-Peak Billing Demand occurring at that point in time.

Educational Institution Service Provision (GEI):

When service is supplied to a school, college or university, a credit shall be applied during all billing months. As used in this provision, "school" shall mean buildings, facilities, playing fields, or property directly or indirectly used for school purposes for children in grades kindergarten through twelve, when provided by a public or nonpublic school. School does not include instruction provided in a private residence or proprietary trade, vocational, training, or occupational school. "College" or "University" shall mean buildings located on the same campus and used to impart instruction, including all adjacent and appurtenant buildings owned by the same customer which are located on the same campus and which constitute an integral part of such college or university facilities.

The monthly credit for the Educational Institution Service Provision shall be applied as follows:

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

Educational Institution Credit: $(~~0.000296~~ *0.000314*) per kWh for all kWh

Customers on this provision shall require a written contract, with a minimum term of one year, and shall be evaluated annually to determine whether or not the accounts shall remain on the service provision.

(Continued on Sheet No. D-34.00)

GENERAL SERVICE PRIMARY DEMAND RATE GPD

(Continued From Sheet No. D-33.00)

Monthly Rate (Contd)

Self-Generation Provision (SG)

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

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

Energy delivered to the Company shall be alternating current, 60-hertz, single-phase or three-phase (as governed by Rule B8., Electric Interconnection and Net Metering Standards) Secondary Voltage or Primary Voltage service. The Company will determine the particular nature of the voltage in each case.

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

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

Sales of Self-Generated Energy to the Company

A customer who meets the Federal Energy Regulatory Commission's (FERC) criteria for a Qualifying Facility may elect to sell energy to the Company. The Company has the right to refuse to contract for the purchase of energy. Sales of energy to the Company under this provision shall require a written contract with a minimum term of one year.

Where the customer elects to sell energy to the Company, an Interval Data Meter (IDM) or other applicable meter is required for their generator. Meter reading will be accomplished electronically through telecommunication links or other electronic data methods able to provide the Company with the metering data / billing determinants necessary for billing purposes.

Administrative Cost Charge

$0.0010 per kWh purchased for generation installations with a capacity of ~~100~~ *550* kW or less.

Energy Purchase

An energy purchase by the Company shall be bought at the Midcontinent Independent System Operator's, Inc. (MISO) real-time Locational Marginal Price (LMP) for the Company's load node (designated as "CONS.CETR" as of the date of this Rate Schedule). The Company may discontinue purchases during system emergencies, maintenance and other operational circumstances.

Interruptible Service Provision (GI)

This provision is available to any customer account willing to contract for at least 500 kW of On-Peak Billing Demand as interruptible. The Company reserves the right to limit the amount of load contracted as interruptible, but in no case shall it exceed ~~75,000~~ *100,000* kW. Customers shall have no more than 50% of their annual On-Peak Billing Demand contracted as interruptible when contracting for more than 50,000 kW of interruptible load. The aggregate amount of monthly On-Peak Billing Demand subscribed under this provision shall be limited to 300,000 kW.

Consumers Energy may require the Customer to monitor and provide real-time, Internet-enabled power monitoring. If such monitoring is required, Consumers Energy will provide the metering or monitoring devices necessary, which shall be owned by Consumers Energy and provided to the Customer at the Company's expense. The Customer may be required to provide suitable space for such monitoring equipment and either a static or non-static, as applicable, Internet Protocol (IP) address and Local Area Network (LAN) access that allows for Internet-based communication of the Customer's site electricity consumption and interruption event performance.

(Continued on Sheet No. D-34.10)

GENERAL SERVICE PRIMARY DEMAND RATE GPD

(Continued From Sheet No. D-34.00)

Monthly Rate (Contd)

Interruptible Service Provision (GI) (Contd)

For billing purposes, the monthly interruptible On-Peak Billing Demand shall be billed first and discounted under this interruptible service provision. The actual On-Peak Billing Demand for the interruptible load supplied shall be credited by the amount specified under the Power Supply Charges - Interruptible Credit listed below. Subsequently all firm service used during the billing period in excess of the contracted interruptible shall be billed at the appropriate firm rate. All contracts under this provision shall be negotiated on an annual basis. The Customer must notify the Company by December 31st of each year of their desire to renew the GI provision and the amount of interruptible kW for the following *capacity planning* year *(June 1 through May 31)*. Within 30 minutes of receiving an interruption notice, the customer shall reduce their total load level by the amount of contracted interruptible capacity or have the total facility subject to interruption.

The minimum On-Peak Billing Demand that shall be billed for the interruptible portion of a customer's bill is the contracted interruptible amount. At the Company's discretion, the customer may reduce the contracted amount one time within the annual contract period.

Any load designated as interruptible by the customer is also subject to Midcontinent Independent System Operator's Inc. (MISO) requirements *for Load Modifying Resources and the Company shall inform the Customer of such MISO requirements. Interruption under this provision may occur if MISO issues a Maximum Generation Emergency Event Step 2b order or NERC Emergency Event Alert 2 notice indicating that MISO is experiencing or expects to experience a shortage of economic resources and the Company has declared Emergency Status. Participation in the GI provision does not limit the Company's ability to implement emergency electrical procedures as described in the Company's Electric Rate Book including interruption of service as required to maintain system integrity* ~~as determined by the Company~~.

Conditions of Interruption

Under this provision, the customer shall be interrupted at any time, on-peak or off-peak, the Company deems it necessary to maintain system integrity. The Company shall provide *the Customer at least thirty minutes advance* notice ~~in advance~~ of ~~probable~~ *a required* interruption, and if possible, a second notice ~~of positive interruption~~. The notice will be communicated by telephone to the contact numbers provided by the Customer. The Customer shall confirm the receipt of such notice through the automated response process. Failure to acknowledge receipt of such notice shall not relieve the customer of the obligation for interruption under the GI Provision. The customer shall be informed, when possible, of the estimated duration of the interruption at the time of interruption.

The Company shall not be liable for any loss or damage caused by or resulting from any interruption of service under this provision.

Interruptions beyond the Company's control, described in Rules C1.1, Character of Service, and C3., Emergency Electrical Procedures, of the Company's Electric Rate Book, shall not be considered as interruptions for purposes of this provision.

Should the Company be ordered by Governmental authority during a national emergency to supply firm instead of interruptible service, billing shall be made on an applicable firm power schedule.

Cost of Customer Non-Interruption

Failure by a customer to comply with a system integrity interruption order of the Company shall be considered as unauthorized use and billed at (i) the higher of the actual damages incurred by the Company or (ii) the rate of $*25.00* ~~50.00~~ per kW for the highest 15-minute kW of Interruptible On-Peak Billing demand created during the interruption period, in addition to the prescribed monthly rate. In addition, the interruptible contract capacity of a customer who does not interrupt within one hour following notice shall be immediately reduced by the amount which the customer failed to interrupt, unless the customer demonstrates that failure to interrupt was beyond its control.

The monthly credit for the Interruptible Service Provision shall be applied as follows:

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

Interruptible Credit:	$(7.00)	per kW of On-Peak Billing Demand during the billing months of June-September
	$(6.00)	per kW of On-Peak Billing Demand during the billing months of October-May

(Continued on Sheet No. D-*34.20* ~~35.00~~)

LARGE GENERAL SERVICE PRIMARY DEMAND RATE GPD

(Continued From Sheet No. D-34.10)

Interruptible Service Provision – Market-Price Option (GI2)

Availability:

This provision is available to any Full Service GPD customer account willing to contract for at least 3,000 kW of On-Peak Billing Demand as interruptible. The Company reserves the right to limit the amount of load contracted as interruptible, but in no case shall it exceed 100,000 kW. The combined aggregate amount of monthly On-Peak Billing Demand subscribed under the GI and GI2 provisions shall be limited to 400,000 kW.

In the event the combined aggregate amount of monthly On-Peak Demand subscribed is less than the approved limit specified above, the Company may offer the remaining capacity, to otherwise eligible customers willing to contract for less than the minimum contract capacity amounts specified above.

The customer may choose to have the interruptible load separately metered. The customer shall bear any expense incurred by the Company in providing a separate service for the interruptible portion of an existing customer load. The customer must provide space suitable for the separate metering. Consumers Energy may require the Customer to monitor and provide real-time, Internet-enabled power monitoring. If such monitoring is required, Consumers Energy will provide the metering or monitoring devices necessary, which shall be owned by Consumers Energy and provided to the Customer at the Company's expense. The Customer may be required to provide suitable space for such monitoring equipment and either a static or non-static, as applicable, Internet Protocol (IP) address and Local Area Network (LAN) access that allows for Internet-based communication of the Customer's site electricity consumption and interruption event performance.

Contract Capacity

Customers shall contract for a specified capacity in kilowatts sufficient to meet the customers' maximum interruptible requirements, but not less than the minimum contract capacity amounts, specified above. The contract capacity shall not be decreased during the term of the contract and subsequent renewal periods as long as service is required unless there is a verified reduction in connected load. Capacity disconnected from service under this provision shall not be subsequently served under any other tariff during the term of this contract and subsequent renewal periods. The Customer must notify and contract with the Company by December 31st of each year of their desire to renew the GI2 provision and the amount of interruptible kW for the following capacity planning year (June 1 through May 31).

Monthly Billing

For billing purposes, the monthly firm service will be billed first on Rate GPD, with the load in excess of contracted firm being billed on the GI2 charges specified in this rate schedule.

Power Supply Charges - These charges are applicable to contracted interruptible capacity.

The customer shall be responsible for the MISO Real-Time Locational Market Price (LMP) for the Company's load node (designated as "CONS.CETR" as the date of this Rate Schedule), multiplied by the customer's consumption (kWh), plus the Market Settlement Fee of $0.002/kWh.

Charges for Customer Voltage Level 3 (CVL 3)

LMP Energy Charge:	*MISO Real-Time LMP per kWh for all kWh*	
Capacity & Transmission Charge:	*$0.049807*	*per kWh for all kWh during the billing months of June-September*
	$0.046476	*per kWh for all kWh during the billing months of October-May*

Charges for Customer Voltage Level 2 (CVL 2)

LMP Energy Charge:	*MISO Real-Time LMP per kWh for all kWh*	
Capacity & Transmission Charge:	*$0.039453*	*per kWh for all kWh during the billing months of June-September*
	$0.036122	*per kWh for all kWh during the billing months of October-May*

Charges for Customer Voltage Level 1 (CVL 1)

LMP Energy Charge:	*MISO Real-Time LMP per kWh for all kWh*	
Capacity & Transmission Charge:	*$0.028890*	*per kWh for all kWh during the billing months of June-September*
	$0.025559	*per kWh for all kWh during the billing months of October-May*

(Continued on Sheet No. D-34.30)

LARGE GENERAL SERVICE PRIMARY DEMAND RATE GPD

(Continued From Sheet No. D-34.20)

Interruptible Service Provision – Market-Price Option (GI2) (Cont)

The MISO Real-Time LMP per kWh shall be adjusted for losses based on the customer's point of metering as shown below:

	Meter Point	
	High Side	Low Side
Customer Voltage Level 1	0.000%	0.705%
Customer Voltage Level 2	1.271%	2.366%
Customer Voltage Level 3	3.221%	7.643%

Delivery Charges – These charges are applicable to contract capacity

Rate GPD Delivery Charges will apply to all Delivery service, including contracted capacity designated as GI2 interruptible service.

System Access Charge:

If contracted capacity is separately metered: *$100.00 per additional meter installation per month*

This provision is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-3.10 and the Power Plant Securitization Charges shown on Sheet No. D-5.10. as well as the System Access Charge, Delivery Charges, General Terms, Adjustment for Power Factor, Substation Ownership Credit, Minimum Charge and the Due Date and Late Payment Charge applicable to Rate GPD.

Conditions of Interruption

The Company will notify the customer as to the amount of total load on this rider to be curtailed. Load identified as monthly firm service and billed on Rate GPD is not considered as interruptible and does not need to be curtailed under the terms of GI2. Although actual load at time of interruption may vary from contract capacity, the total measured load on this provision shall be subject to curtailment by the Company.

The Company shall provide the Customer at least thirty minutes advance notice of a required interruption, and if possible, a second notice. The notice will be communicated by telephone to the contact numbers provided by the Customer. The Customer shall confirm the receipt of such notice through the automated response process. Failure to acknowledge receipt of such notice shall not relieve the customer of the obligation for interruption under the GI Provision. The customer shall be informed, when possible, of the estimated duration of the interruption at the time of interruption. Within 30 minutes of receiving an interruption notice, the customer shall reduce their total load level by the amount of contracted interruptible capacity or have the total facility subject to interruption.

Any load designated as interruptible by the customer may require the installation and maintenance of equipment that allow the Company to remotely interrupt the customer's load. If the company determines it is required to install and maintain equipment at the customer's site to comply with any requirements associated with the GI service provision then it shall do so at the customer's expense. In addition, the customer shall also adhere to any advance notification requirements the Company deems are necessary to comply with its obligations to MISO under this provision.

Any load designated as interruptible by the customer is also subject to Midcontinent Independent System Operator's Inc. (MISO) requirements for Load Modifying Resources and the Company shall inform the Customer of such MISO requirements. Interruption under this provision may occur if MISO issues a Maximum Generation Emergency Event Step 2b order or NERC Emergency Event Alert 2 notice indicating that MISO is experiencing or expects to experience a shortage of economic resources and the Company has declared Emergency Status. Participation in the GI provision does not limit the Company's ability to implement emergency electrical procedures as described in the Company's Electric Rate Book including interruption of service as required to maintain system integrity.

(Continued on Sheet No. D-34.40)

LARGE GENERAL SERVICE PRIMARY DEMAND RATE GPD

(Continued From Sheet No. D-34.30)

Interruptible Service Provision – Market-Price Option (GI2) (Cont)

Under this provision, the customer shall be interrupted at any time, on-peak or off-peak, the Company deems it necessary to maintain system integrity. The Company shall provide notice in advance of probable interruption, and if possible, a second notice of positive interruption. The notice will be communicated by telephone to the contact numbers provided by the Customer. The Customer shall confirm the receipt of such notice through the automated response process. Failure to acknowledge receipt of such notice shall not relieve the Customer of the obligation for interruption under the GI2 provision. The customer shall be informed, when possible, of the estimated duration of the interruption at the time of interruption.

The Company shall not be liable for any loss or damage caused by or resulting from any interruption of service under this provision.

Interruptions beyond the Company's control, described in Rules C1.1, Character of Service, and C3., Emergency Electrical Procedures, of the Company's Electric Rate Book, shall not be considered as interruptions for purposes of this provision.

Should the Company be ordered by Governmental authority during a national emergency to supply firm instead of interruptible service, billing shall be made on an applicable firm power schedule.

Cost of Customer Non-Interruption

Failure by a customer to comply with a system integrity interruption order of the Company shall be considered as unauthorized use and billed at (i) the higher of the actual damages incurred by the Company or (ii) the rate of $25.00 per kW for the highest 15-minute kW of Interruptible On-Peak Billing demand created during the interruption period, in addition to the prescribed monthly rate. In addition, the interruptible contract capacity of a customer who does not interrupt within one hour following notice shall be immediately reduced by the amount which the customer failed to interrupt, unless the customer demonstrates that failure to interrupt was beyond its control.

(Continued on Sheet No. D-35.00)

LARGE GENERAL SERVICE PRIMARY DEMAND RATE GPD

(Continued From Sheet No. D-~~34.10~~ *34.40*)

Monthly Rate: (Contd)

Net Metering Program:

The Net Metering Program is available to any eligible customer as described in Rule C11., Net Metering Program, who desires to generate a portion or all of their own retail electricity requirements using a Renewable Energy Resource as defined in Rule C11.B, Net Metering Definitions.

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

Green Generation Program:

Customer contracts for participation in the Green Generation Program shall be available to any eligible customer as described in Rule C10.2, Green Generation Program.

A customer who participates in the Green Generation Program is subject to the provisions contained in Rule C10.2, Green Generation Program.

General Terms:

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

Minimum Charge:

The System Access Charge included in the rate, and applicable any non-consumption based surcharges.

Due Date and Late Payment Charge:

The due date of the customer bill shall be 21 days from the date of mailing. A late payment charge of 2% of the unpaid balance, net of taxes, shall be assessed to any bill which is not paid on or before the due date shown thereon.

Term and Form of Contract:

For customers with monthly demands of 300 kW or more, all service under this rate shall require a written contract with a minimum term of one year.

For customers with monthly demands of less than 300 kW, service under this rate shall not require a written contract except for: (i) service under the Resale Service Provision, (ii) service under the Green Generation Program, (iii) service under the Educational Institution Service Provision, (iv) service under the Aggregate Peak Demand Service Provision, (v) service under the Interruptible Service Provision, or (vi)at the option of the Company. If a contract is deemed necessary by the Company, the appropriate contract form shall be used and the contract shall require a minimum term of one year.

A new contract will not be required for existing customers who increase their demand requirements after initiating service, unless new or additional facilities are required or service provisions deem it necessary.

Attachment 2
To Settlement Agreement In Case No. U-20134

GENERAL SERVICE PRIMARY TIME-OF-USE RATE GPTU

(Continued from Sheet No. D-36.10)

Monthly Rate:

Power Supply Charges

Charges for Customer Voltage Level 3 (CVL 3)

Energy Charge:

	Non-Capacity	Capacity	Total	
Off-Peak - Summer	$~~0.055489~~ 0.056286	$~~0.020130~~ 0.020681	$~~0.075619~~ 0.076967	per kWh during the calendar months of June – September
Low-Peak - Summer	$~~0.072903~~ 0.072924	$~~0.024660~~ 0.025299	$~~0.097563~~ 0.098223	per kWh during the calendar months of June – September
Mid-Peak - Summer	$~~0.087210~~ 0.088694	$~~0.028381~~ 0.029676	$~~0.115591~~ 0.118370	per kWh during the calendar months of June – September
High-Peak - Summer	$~~0.093275~~ 0.100060	$~~0.029959~~ 0.032831	$~~0.123234~~ 0.132891	per kWh during the calendar months of June – September
Off-Peak - Winter	$~~0.054854~~ 0.056918	$~~0.019965~~ 0.020856	$~~0.074819~~ 0.077774	per kWh during the calendar months of October – May
Mid-Peak - Winter	$~~0.061668~~ 0.063823	$~~0.021737~~ 0.022773	$~~0.083405~~ 0.086596	per kWh during the calendar months of October – May
High-Peak - Winter	$~~0.064524~~ 0.065501	$~~0.022480~~ 0.023239	$~~0.087004~~ 0.088740	per kWh during the calendar months of October – May

Charges for Customer Voltage Level 2 (CVL 2)

Energy Charge:

	Non-Capacity	Capacity	Total	
Off-Peak - Summer	$~~0.049789~~ 0.051286	$~~0.014430~~ 0.015681	$~~0.064219~~ 0.066967	per kWh during the calendar months of June – September
Low-Peak - Summer	$~~0.067203~~ 0.067924	$~~0.018960~~ 0.020299	$~~0.086163~~ 0.088223	per kWh during the calendar months of June – September
Mid-Peak - Summer	$~~0.081510~~ 0.083694	$~~0.022681~~ 0.024676	$~~0.104191~~ 0.108370	per kWh during the calendar months of June – September
High-Peak - Summer	$~~0.087575~~ 0.095060	$~~0.024259~~ 0.027831	$~~0.111834~~ 0.122891	per kWh during the calendar months of June – September
Off-Peak - Winter	$~~0.049154~~ 0.051918	$~~0.014265~~ 0.015856	$~~0.063419~~ 0.067774	per kWh during the calendar months of October – May
Mid-Peak - Winter	$~~0.055968~~ 0.058823	$~~0.016037~~ 0.017773	$~~0.072005~~ 0.076596	per kWh during the calendar months of October – May
High-Peak - Winter	$~~0.058824~~ 0.060501	$~~0.016780~~ 0.018239	$~~0.075604~~ 0.078740	per kWh during the calendar months of October – May

Charges for Customer Voltage Level 1 (CVL 1)

Energy Charge:

	Non-Capacity	Capacity	Total	
Off-Peak - Summer	$~~0.047789~~ 0.049286	$~~0.012430~~ 0.013681	$~~0.060219~~ 0.062967	per kWh during the calendar months of June – September
Low-Peak - Summer	$~~0.065203~~ 0.065924	$~~0.016960~~ 0.018299	$~~0.082163~~ 0.084223	per kWh during the calendar months of June – September
Mid-Peak - Summer	$~~0.079510~~ 0.081694	$~~0.020681~~ 0.022676	$~~0.100191~~ 0.104370	per kWh during the calendar months of June – September
High-Peak - Summer	$~~0.085575~~ 0.093060	$~~0.022259~~ 0.025831	$~~0.107834~~ 0.118891	per kWh during the calendar months of June – September
Off-Peak - Winter	$~~0.047154~~ 0.049918	$~~0.012265~~ 0.013856	$~~0.059419~~ 0.063774	per kWh during the calendar months of October – May
Mid-Peak - Winter	$~~0.053968~~ 0.056823	$~~0.014037~~ 0.015773	$~~0.068005~~ 0.072596	per kWh during the calendar months of October – May
High-Peak - Winter	$~~0.056824~~ 0.058501	$~~0.014780~~ 0.016239	$~~0.071604~~ 0.074740	per kWh during the calendar months of October – May

Attachment 2
To Settlement Agreement In Case No. U-20134

Delivery Charges

System Access Charge: $200.00 per customer per month

Charges for Customer Voltage Level 3 (CVL 3)

Capacity Charge: $~~4.20~~ *3.60* per kW of Maximum Demand

Charges for Customer Voltage Level 2 (CVL 2)

Capacity Charge: $~~1.85~~ *1.86* per kW of Maximum Demand

Charges for Customer Voltage Level 1 (CVL 1)

Capacity Charge: $~~0.96~~ *0.91* per kW of Maximum Demand

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-3.10 and the Power Plant Securitization Charges shown on Sheet No. D-5.10.

Adjustment for Power Factor

This rate requires a determination of the average Power Factor maintained by the customer during the billing period. Such average Power Factor shall be determined through metering of lagging Kilovar-hours and Kilowatt-hours during the billing period. The calculated ratio of lagging Kilovar-hours to Kilowatt-hours shall then be converted to the average Power Factor for the billing period by using the appropriate conversion factor. Whenever the average Power Factor during the billing period is above .899 or below .850, the customer bill shall be adjusted as follows:

(Continued on Sheet No. D-36.30)

GENERAL SERVICE PRIMARY TIME-OF-USE RATE GPTU

(Continued from Sheet No. D-36.20)

Monthly Rate (Contd)

Adjustment for Power Factor (Contd)

(a) If the average Power Factor during the billing period is .900 or higher, a 0.50% credit will be applied to all metered-based charges, excluding surcharges. This credit shall not in any case be used to reduce the prescribed Minimum Charge.

(b) If the average Power Factor during the billing period is less than .850, a penalty will be applied to all metered-based charges, excluding surcharges, in accordance with the following table:

Power Factor	Penalty
0.800 to 0.849	0.50%
0.750 to 0.799	1.00%
0.700 to 0.749	2.00%
Below 0.700	3% first 2 months

(c) A Power Factor less than 0.700 is not permitted and necessary corrective equipment must be installed by the customer. A 15% penalty will be applied to any metered-based charges, excluding surcharges, after two consecutive months below 0.700 Power Factor and will continue as long as the Power Factor remains below 0.700. Once the customer's Power Factor exceeds 0.700, it is necessary to complete two consecutive months below 0.700 before the 15% penalty applies again.

Maximum Demand

The Maximum Demand shall be the highest 15-minute demand created during the current month or previous 11 months.

Resale Service Provision:

Subject to any restrictions, this provision is available to customers desiring Primary Voltage service for resale purposes in accordance with Rule C4.4, Resale.

Substation Ownership Credit

Where service is supplied at a nominal voltage of more than 25,000 volts, energy is measured through an Interval Data Meter, and the customer provides all the necessary transforming, controlling and protective equipment for all the service there shall be deducted from the bill a monthly credit. For those customers, part of whose load is served through customer-owned equipment, the credit shall be based on the Maximum Demand.
The monthly substation ownership credit shall be applied as follows:

Delivery Charges - These charges are applicable to Full Service Customers.

Charges for Customer Voltage Level 2 (CVL 2)
Substation Ownership Credit: $(~~0.65~~ *0.97*) per kW of Maximum Demand

Charges for Customer Voltage Level 1 (CVL 1)
Substation Ownership Credit: $(~~0.38~~ *0.45*) per kW of Maximum Demand

For those customers served by more than one substation where one or more of the substations is owned by the customer, the credit will be applied to the customer's coincident Maximum Demand for those substations owned by the customer. This credit shall not operate to reduce the customer's billing below the prescribed minimum charges included in the rate. The credit shall be based on the kW after the 1% deduction or 3% addition has been applied to the metered kW.

Educational Institution Service Provision (GEI)

When service is supplied to a school, college or university, a credit shall be applied during all billing months. As used in this provision, "school" shall mean buildings, facilities, playing fields, or property directly or indirectly used for school purposes for children in grades kindergarten through twelve, when provided by a public or nonpublic school. School does not include instruction provided in a private residence or proprietary trade, vocational, training, or occupational school. "College" or "University" shall mean buildings located on the same campus and used to impart instruction, including all adjacent and appurtenant buildings owned by the same customer which are located on the same campus and which constitute an integral part of such college or university facilities.
The monthly credit for the Educational Institution Service Provision shall be applied as follows:

Delivery Charges - These charges are applicable to Full Service Customers.

Educational Institution Credit: $(~~0.000296~~ *0.000314*) per kWh for all kWh

Customers on this provision shall require a written contract, with a minimum term of one year, and shall be evaluated annually to determine whether or not the accounts shall remain on the service provision.

(Continued on Sheet No. D-36.40)

GENERAL SERVICE PRIMARY TIME-OF-USE RATE GPTU

(Continued from Sheet No. D-36.30)

Self-Generation Provision (SG)

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

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

Energy delivered to the Company shall be alternating current, 60-hertz, single-phase or three-phase (as governed by Rule B8., Electric Interconnection and Net Metering Standards) Secondary Voltage or Primary Voltage service. The Company will determine the particular nature of the voltage in each case.

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

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

Sales of Self-Generated Energy to the Company

A customer who meets the Federal Energy Regulatory Commission's (FERC) criteria for a Qualifying Facility may elect to sell energy to the Company. The Company has the right to refuse to contract for the purchase of energy. Sales of energy to the Company under this provision shall require a written contract with a minimum term of one year.

Where the customer elects to sell energy to the Company, an Interval Data Meter (IDM) or other applicable meter is required for their generator. Meter reading will be accomplished electronically through telecommunication links or other electronic data methods able to provide the Company with the metering data / billing determinants necessary for billing purposes.

Administrative Cost Charge

$0.0010 per kWh purchased for generation installations with a capacity of ~~100~~ *550* kW or less.

Energy Purchase

An energy purchase by the Company shall be bought at the Midcontinent Independent System Operator's, Inc. (MISO) real-time Locational Marginal Price (LMP) for the Company's load node (designated as "CONS.CETR" as of the date of this Rate Schedule). The Company may discontinue purchases during system emergencies, maintenance and other operational circumstances.

Green Generation Program

Customer contracts for participation in the Green Generation Program shall be available to any eligible customer as described in Rule C10.2, Green Generation Program.

A customer who participates in the Green Generation Program is subject to the provisions contained in Rule C10.2, Green Generation Program.

General Terms

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

Minimum Charge

The System Access Charge included in the rate, and any applicable non-consumption based surcharges.

Due Date and Late Payment Charge

The due date of the customer bill shall be 21 days from the date of mailing. A late payment charge of 2% of the unpaid balance, net of taxes, shall be assessed to any bill which is not paid on or before the due date shown thereon.

Term and Form of Contract

Service under this rate shall require a written contract with a minimum term of one year.

ENERGY INTENSIVE PRIMARY RATE EIP
(Continued from Sheet No. D-37.00)

Schedule of Hours:

The following schedule shall apply Monday through Friday (except holidays designated by the Company):

Summer:	
Off-Peak Hours:	12:00 AM to 6:00 AM and 11:00 PM to 12:00 AM
Low-Peak Hours:	6:00 AM to 2:00 PM and 6:00 PM to 11:00 PM
Mid-Peak Hours:	2:00 PM to 3:00 PM and 5:00 PM to 6:00 PM
High-Peak Hours:	3:00 PM to 5:00 PM
Critical Peak Hours:	3:00 PM to 5:00 PM during a Critical Peak Event
Winter:	
Off-Peak Hours:	12:00 AM to 4:00 PM and 8:00 PM to 12:00 AM
Mid-Peak Hours:	4:00 PM to 5:00 PM and 7:00 PM to 8:00 PM
High-Peak Hours:	5:00 PM to 7:00 PM
Critical Peak Hours:	5:00 PM to 7:00 PM during a Critical Peak Event

Weekends and holidays are off-peak. Designated Company holidays are: New Year's Day - January 1; Memorial Day - Last Monday in May; Independence Day - July 4; Labor Day - First Monday in September; Thanksgiving Day - Fourth Thursday in November; and Christmas Day - December 25. Whenever January 1, July 4, or December 25 fall on Sunday, extended holiday periods such as Monday, January 2, Monday, July 5 and Monday, December 26 shall not be considered as holidays for application of off-peak hours.

Monthly Rate:

Power Supply Charges:

Charges for Customer Voltage Level 3 (CVL 3)

Energy Charge:

	Non-Capacity	Capacity	Total	
Off-Peak - Summer	$~~0.038938~~ *0.035312*	$~~0.008254~~ *0.017089*	$~~0.047192~~ *0.052401*	per kWh during the calendar months of June – September
Low-Peak - Summer	$~~0.050262~~ *0.049172*	$~~0.014146~~ *0.023367*	$~~0.064408~~ *0.072539*	per kWh during the calendar months of June – September
Mid-Peak - Summer	$~~0.05566~~ *0.060664*	$~~0.018987~~ *0.028572*	$~~0.078553~~ *0.089236*	per kWh during the calendar months of June – September
High-Peak - Summer	$~~0.063349~~ *0.065164*	$~~0.020955~~ *0.030610*	$~~0.084304~~ *0.095774*	per kWh during the calendar months of June – September
Critical Peak - Summer		the greater of either 150% of the High-Peak - Summer Energy Charge or the average Market price per kWh for a Critical Peak Event during the calendar months of June – September		
Off-Peak - Winter	$~~0.040001~~ *0.035492*	$~~0.008807~~ *0.017170*	$~~0.048808~~ *0.052662*	per kWh during the calendar months of October – May
Mid-Peak - Winter	$~~0.049433~~ *0.049652*	$~~0.013715~~ *0.023584*	$~~0.063148~~ *0.073236*	per kWh during the calendar months of October – May
High-Peak - Winter	$~~0.059791~~ *0.062539*	$~~0.019104~~ *0.029421*	$~~0.078895~~ *0.091960*	per kWh during the calendar months of October – May
Critical Peak - Winter		the greater of either 150% of the High-Peak - Winter Energy Charge or the average Market price per kWh for a Critical Peak Event during the calendar months of October – May		

(Continued on Sheet No. D-37.20)

ENERGY INTENSIVE PRIMARY RATE EIP

(Continued from Sheet No. D-37.10)

Power Supply Charges: (Contd)

Charges for Customer Voltage Level 2 (CVL 2)

Energy Charge:

	Non-Capacity	Capacity	Total	
Off-Peak - Summer	$~~0.033238~~ 0.038312	$~~0.019254~~ 0.020089	$~~0.052492~~ 0.058401	per kWh during the calendar months of June – September
Low-Peak - Summer	$~~0.044562~~ 0.052172	$~~0.025146~~ 0.026367	$~~0.069708~~ 0.078539	per kWh during the calendar months of June – September
Mid-Peak - Summer	$~~0.053866~~ 0.063664	$~~0.029987~~ 0.031572	$~~0.083853~~ 0.095236	per kWh during the calendar months of June – September
High-Peak - Summer	$~~0.057649~~ 0.068164	$~~0.031955~~ 0.033610	$~~0.089604~~ 0.101774	per kWh during the calendar months of June – September
Critical Peak - Summer		the greater of either 150% of the High-Peak - Summer Energy Charge or the average Market price per kWh for a Critical Peak Event during the calendar months of June – September		
Off-Peak - Winter	$~~0.034301~~ 0.038492	$~~0.019807~~ 0.020170	$~~0.054108~~ 0.058662	per kWh during the calendar months of October – May
Mid-Peak - Winter	$~~0.043733~~ 0.052652	$~~0.024715~~ 0.026584	$~~0.068448~~ 0.079236	per kWh during the calendar months of October – May
High-Peak - Winter	$~~0.054091~~ 0.065539	$~~0.030104~~ 0.032421	$~~0.084195~~ 0.097960	per kWh during the calendar months of October – May
Critical Peak - Winter		the greater of either 150% of the High-Peak - Winter Energy Charge or the average Market price per kWh for a Critical Peak Event during the calendar months of October – May		

Charges for Customer Voltage Level 1 (CVL 1)

Energy Charge:

	Non-Capacity	Capacity	Total	
Off-Peak - Summer	$~~0.031238~~ 0.033312	$~~0.016254~~ 0.015089	$~~0.047492~~ 0.048401	per kWh during the calendar months of June – September
Low-Peak - Summer	$~~0.042562~~ 0.047172	$~~0.022146~~ 0.021367	$~~0.064708~~ 0.068539	per kWh during the calendar months of June – September
Mid-Peak - Summer	$~~0.051866~~ 0.058664	$~~0.026987~~ 0.026572	$~~0.078853~~ 0.085236	per kWh during the calendar months of June – September
High-Peak - Summer	$~~0.055649~~ 0.063164	$~~0.028955~~ 0.028610	$~~0.084604~~ 0.091774	per kWh during the calendar months of June – September
Critical Peak - Summer		the greater of either 150% of the High-Peak - Summer Energy Charge or the average Market price per kWh for a Critical Peak Event during the calendar months of June – September		
Off-Peak - Winter	$~~0.032301~~ 0.033492	$~~0.016807~~ 0.015170	$~~0.049108~~ 0.048662	per kWh during the calendar months of October – May
Mid-Peak - Winter	$~~0.041733~~ 0.047652	$~~0.021715~~ 0.021584	$~~0.063448~~ 0.069236	per kWh during the calendar months of October – May
High-Peak - Winter	$~~0.052091~~ 0.060539	$~~0.027104~~ 0.027421	$~~0.079195~~ 0.087960	per kWh during the calendar months of October – May
Critical Peak - Winter		the greater of either 150% of the High-Peak - Winter Energy Charge or the average Market price per kWh for a Critical Peak Event during the calendar months of October – May		

Delivery Charges:

System Access Charge:	$200.00	per customer per month

Attachment 2
To Settlement Agreement In Case No. U-20134

Charges for Customer Voltage Level 3 (CVL 3):

Capacity Charge: $~~4.20~~ *3.60* per kW of Maximum Demand

Charges for Customer Voltage Level 2 (CVL 2):

Capacity Charge: $~~1.85~~ *1.86* per kW of Maximum Demand

Charges for Customer Voltage Level 1 (CVL 1):

Capacity Charge: $~~0.96~~ *0.91* per kW of Maximum Demand

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-3.10 and the Power Plant Securitization Charges shown on Sheet No. D-5.10.

(Continued on Sheet No. D-37.30)

ENERGY INTENSIVE PRIMARY RATE EIP

(Continued from Sheet No. D-37.20)

Adjustment for Power Factor:

This rate requires a determination of the average Power Factor maintained by the customer during the billing period. Such average Power Factor shall be determined through metering of lagging Kilovar-hours and Kilowatt-hours during the billing period. The calculated ratio of lagging Kilovar-hours to Kilowatt-hours shall then be converted to the average Power Factor for the billing period by using the appropriate conversion factor. Whenever the average Power Factor during the billing period is above .899 or below .850, the customer bill shall be adjusted as follows:

(a) If the average Power Factor during the billing period is .900 or higher, a 0.50% credit will be applied to all metered-based charges, excluding surcharges. This credit shall not in any case be used to reduce the prescribed Minimum Charge.

(b) If the average Power Factor during the billing period is less than .850, a penalty will be applied to all metered-based charges, excluding surcharges, in accordance with the following table:

Power Factor	**Penalty**
0.800 to 0.849	0.50%
0.750 to 0.799	1.00%
0.700 to 0.749	2.00%
Below 0.700	3% first 2 months

(c) A Power Factor less than 0.700 is not permitted and necessary corrective equipment must be installed by the customer. A 15% penalty will be applied to any metered-based charges, excluding surcharges, after two consecutive months below 0.700 Power Factor and will continue as long as the Power Factor remains below 0.700. Once the customer's Power Factor exceeds 0.700, it is necessary to complete two consecutive months below 0.700 before the 15% penalty applies again.

Maximum Demand:

The Maximum Demand shall be the highest 15-minute demand created during the current month or previous 11 months.

Substation Ownership Credit

Where service is supplied at a nominal voltage of more than 25,000 volts, energy is measured through an Interval Data Meter, and the customer provides all the necessary transforming, controlling and protective equipment for all the service there shall be deducted from the bill a monthly credit. For those customers, part of whose load is served through customer-owned equipment, the credit shall be based on the Maximum Demand.

The monthly substation ownership credit shall be applied as follows:

Delivery Charges - These charges are applicable to Full Service Customers.

Charges for Customer Voltage Level 2 (CVL 2)

Substation Ownership Credit: $(~~0.65~~ *0.97*) per kW of Maximum Demand

Charges for Customer Voltage Level 1 (CVL 1)

Substation Ownership Credit: $(~~0.38~~ *0.45*) per kW of Maximum Demand

For those customers served by more than one substation where one or more of the substations is owned by the customer, the credit will be applied to the customer's coincident Maximum Demand for those substations owned by the customer. This credit shall not operate to reduce the customer's billing below the prescribed minimum charges included in the rate. The credit shall be based on the kW after the 1% deduction or 3% addition has been applied to the metered kW.

Self-Generation Provision (SG):

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

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

(Continued on Sheet No. D-37.40)

ENERGY INTENSIVE PRIMARY RATE EIP

(Continued from Sheet No. D-37.30)

Self-Generation Provision (SG) (Contd)

Energy delivered to the Company shall be alternating current, 60-hertz, single-phase or three-phase (as governed by Rule B8., Electric Interconnection and Net Metering Standards) Secondary Voltage or Primary Voltage service. The Company will determine the particular nature of the voltage in each case.

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

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

Sales of Self-Generated Energy to the Company:

A customer who meets the Federal Energy Regulatory Commission's (FERC) criteria for a Qualifying Facility may elect to sell energy to the Company. The Company has the right to refuse to contract for the purchase of energy. Sales of energy to the Company under this provision shall require a written contract with a minimum term of one year.

Where the customer elects to sell energy to the Company, an Interval Data Meter (IDM) or other applicable meter is required for their generator. Meter reading will be accomplished electronically through telecommunication links or other electronic data methods able to provide the Company with the metering data /billing determinants necessary for billing purposes.

Administrative Cost Charge: $0.0010 per kWh purchased for generation installations with a capacity of ~~100~~ *550* kW or less.

Energy Purchase:

An energy purchase by the Company shall be bought at the Midcontinent Independent System Operator's Inc. (MISO) real-time Locational Marginal Price (LMP) for the Company's load node (designated as "CONS.CETR" as of the date of this Rate Schedule). The Company may discontinue purchases during system emergencies, maintenance and other operational circumstances.

Green Generation Programs:

Customer contracts for participation in the Green Generation Program shall be available to any eligible customer as described in Rule C10.2, Green Generation Program.

A customer who participates in the Green Generation Program is subject to the provisions contained in Rule C10.2, Green Generation Program.

General Terms:

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

Minimum Charge:

The System Access Charge included in the rate and any applicable non-consumption based surcharges.

Due Date and Late Payment Charge:

The due date of the customer bill shall be 21 days from the date of mailing. A late payment charge of 2% of the unpaid balance, net of taxes, shall be assessed to any bill which is not paid on or before the due date shown thereon.

Term and Form of Contract:

Service under this rate shall require a written contract with a minimum term of one year.

GENERAL SERVICE SELF GENERATION RATE GSG-2

(Continued From Sheet No. D-42.00)

Nature of Service (Contd)

Where service is supplied at a nominal voltage equal to or greater than 2,400 volts and the Company elects to measure the service at a nominal voltage above 25,000 volts, 1% shall be deducted for billing purposes, from the demand and energy measurements thus made.

Where service is supplied at a nominal voltage equal to or greater than 2,400 volts and the Company elects to measure the service at a nominal voltage of less than 2,400 volts, 3% shall be added for billing purposes, to the demand and energy measurements thus made.

Where service is supplied at a nominal voltage less than 2,400 volts and the Company elects to measure the service at a nominal voltage equal to or greater than 2,400 volts, 3% shall be deducted for billing purposes from the energy measurements thus made.

There shall be no double billing of demand under the base rate and Rate GSG-2.

Monthly Rate

Standby Charges

Power Supply Standby Charges

For all standby energy supplied by the Company , the customer shall be responsible for the MISO Real-Time Locational Market Price (LMP) for the Company's load node (designated as "CONS.CETR" as of the date of this Rate Schedule), multiplied by the customer’s consumption (kWh), plus the Market Settlement Fee of $0.002/kWh. In addition capacity charges will be assessed monthly, calculated using the highest 15 minute kW demand associated with Standby Service occurring during the Company's On-Peak billing hours will be multiplied by the highest contracted capacity purchased by the Company in that month, plus allocated transmission and ancillaries. The capacity charges will be prorated based on the number of On-Peak days that Standby Service was used during the billing month.

A customer with a generator(s) nameplate rating more than 550 kW must provide written notice to the Company by December 1 if they desire standby service in the succeeding calendar months of June through September. Written notice shall be submitted on Company Form 500. If the customer fails to meet this written notice requirement, the LMP shall be increased by applying a 10% adder.

Real Power Losses

Real Power Losses shall be measured based on the transmission loss factor of 2.04% plus the associated meter point as listed below:

	Meter Point	
	High Side	Low Side
Customer Voltage Level 1	0.000%	~~0.690~~ *0.705*%
Customer Voltage Level 2	~~1.390~~ *1.271* %	~~2.480~~ *2.366*%
Customer Voltage Level 3	~~3.660~~ *3.221*%	~~7.900~~ *7.643*%

Delivery Standby Charges

System Access Charge:
Generator that does not meet or exceed load: $100.00 per generator installation per month
Generator that meets or exceeds load: $200.00 per generator installation per month

Charges for Customer Voltage Level 3 (CVL 3)
Capacity Charge: $ ~~4.20~~ *3.60* per kW of Standby Demand

Charges for Customer Voltage Level 2 (CVL 2)
Capacity Charge: $ ~~1.85~~ *1.86* per kW of Standby Demand

Charges for Customer Voltage Level 1 (CVL 1)
Capacity Charge: $ ~~0.96~~ *0.91* per kW of Standby Demand

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-3.10 and the Power Plant Securitization Charges shown on Sheet No. D-5.10.

(Continued on Sheet No. D-44.00)

GENERAL SERVICE SELF GENERATION RATE GSG-2

(Continued From Sheet No. D-43.00)

Monthly Rate (Contd)

Standby Charges (Contd)

Adjustment for Power Factor

This rate requires a determination of the average Power Factor maintained by the customer during the billing period. Such average Power Factor shall be determined through metering of lagging Kilovar-hours and Kilowatt-hours during the billing period. The calculated ratio of lagging Kilovar-hours to Kilowatt-hours shall then be converted to the average Power Factor for the billing period by using the appropriate conversion factor. Whenever the average Power Factor during the billing period is above .899 or below .850, the customer bill shall be adjusted as follows:

(a) If the average Power Factor during the billing period is .900 or higher, a 0.50% credit will be applied to all metered-based charges, excluding surcharges. This credit shall not in any case be used to reduce the prescribed Minimum Charge.

(b) If the average Power Factor during the billing period is less than .850, a penalty will be applied to all metered-based charges, excluding surcharges, in accordance with the following table:

Power Factor	Penalty
0.800 to 0.849	0.50%
0.750 to 0.799	1.00%
0.700 to 0.749	2.00%
Below 0.700	3% first 2 months

(c) A Power Factor less than 0.700 is not permitted and necessary corrective equipment must be installed by the customer. A 15% penalty will be applied to any metered-based charges, excluding surcharges, after two consecutive months below 0.700 Power Factor and will continue as long as the Power Factor remains below 0.700.Once the customer's Power Factor exceeds 0.700, it is necessary to complete two consecutive months below 0.700 before the 15%penalty applies again.

Substation Ownership Credit

Where service is supplied at a nominal voltage of more than 25,000 volts, energy is measured through an Interval Data Meter, and the customer provides all of the necessary transforming, controlling and protective equipment for all of the service there shall be deducted from the bill a monthly credit. For those customers, part of whose load is served through customer-owned equipment, the credit shall be based on the billed Standby Demand.
The monthly credit for the substation ownership shall be applied as follows:

Delivery Charges

Charges for Customer Voltage Level 2 (CVL 2)
Substation Ownership Credit: $(~~0.65~~ *0.97*) per kW of Maximum Demand

Charges for Customer Voltage Level 1 (CVL 1)
Substation Ownership Credit: $(~~0.38~~ *0.45*) per kW of Maximum Demand

For those customers served by more than one substation where one or more of the substations is owned by the customer, the credit will be applied to the customer's coincident Maximum Demand for those substations owned by the customer. This credit shall not operate to reduce the customer’s billing below the prescribed minimum charges included in the rate. The credit shall be based on the kW after the 1% deduction or 3% addition has been applied to the metered kW.

(Continued on Sheet No. D-45.00)

GENERAL SERVICE SELF GENERATION RATE GSG-2

(Continued From Sheet No. D-44.00)

Monthly Rate(Contd)

Standby Charges (Contd)

Transmission Interconnect Credit

Where standby service is provided to a non-utility electric generator located within the Company's service territory and taking power through its transmission interconnect, where the Company has no owned infrastructure other than metering, including billing grade current transformers and potential transformers, telemetry facilities and associated wiring, the following monthly credit shall be applied to the bill:

Delivery Charges

Transmission Interconnect Credit: $ (~~0.96~~ *0.91*)per kW of Standby Demand

This credit shall be based on the kW after the 1% deduction has been applied to the metered kW. The credit supersedes any applicable substation ownership credit.

Sales of Energy to the Company

Administrative Cost Charge

Generation installation with a capacity of over 550 kW but less than or equal to 2,000 kW
As negotiated or $0.0010 per kWh purchased, at the option of the customer

Generation installation with a capacity of over 2,000 kW
As negotiated

Energy Purchase:

An energy purchase by the Company shall be bought at the Midcontinent Independent System Operator's Inc. (MISO) real-time Locational Marginal Price (LMP) for the Company's load node (designated as "CONS.CETR" as of the date of this Rate Schedule).

General Terms

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

Green Generation Program

Customer contracts for participation in the Green Generation Program shall be available to any eligible customer as described in Rule C10.2, Green Generation Program.

A customer who participates in the Green Generation Program is subject to the provisions contained in Rule C10.2, Green Generation Program.

Minimum Charge

The System Access Charge included in this Rate Schedule in addition to the customer's contracted Standby Capacity multiplied by the net of any Substation Ownership Credit and Delivery Capacity Charges of this Rate Schedule.

Due Date and Late Payment Charge

The due date of the customer bill shall be 21 days from the date of mailing. A late payment charge of 2% of the unpaid balance, net of taxes, shall be assessed to any bill which is not paid on or before the due date shown thereon.

Term and Form of Contract

Standby service and/or sales of energy to the Company under this rate shall require a written contract with a minimum term of one year.

GENERAL SERVICE METERED LIGHTING RATE GML

Availability

Subject to any restrictions, this rate is available to any political subdivision or agency of the State of Michigan having jurisdiction over public streets or roadways, for Primary or Secondary Voltage energy-only metered lighting service where the Company has existing distribution lines available for supplying energy for such service. Luminaires which are served under the Company's unmetered lighting rates shall not be intermixed with luminaires served under this metered lighting rate. Luminaire types in addition to those served on Rate Schedule GUL, such as light-emitting diode (LED) streetlights, may receive service under this Rate Schedule.

This rate is not available for resale purposes or for Retail Open Access Service.

Nature of Service

Secondary Voltage

Service under this rate shall be alternating current, 60-hertz, single-phase or three-phase (at the Company's option), 120/240 nominal Volt service for a minimum of ten luminaires located within a clearly defined area. Control equipment shall be furnished, owned and maintained by the Company. The customer shall furnish, install, own and maintain the rest of the equipment comprising the metered lighting system including, but not limited to, the overhead wires or underground cables between the luminaires, protective equipment, and the supply circuits extending to the point of attachment with the Company's distribution system. The Company shall connect the customer's equipment to the Company's lines and supply the energy for its operation. All of the customer's equipment shall be subject to the Company's approval. The customer shall not change the capacity requirements of the equipment owned by it without first notifying the Company in writing of such changes and the date that they shall be made.

Dusk to Midnight Service

Dusk to midnight service shall be the same as Secondary service except:

The customer shall pay the difference between the cost of the control equipment necessary for dusk to midnight service and control equipment normally installed for Secondary service. Circuits shall be arranged approximating minimum loads of 3 kW.

Primary Voltage

Service under this rate shall be alternating current, 60-hertz, single-phase or three-phase (at the Company's option), Primary Voltage service for actual kW demands of not less than 100 kW for each point of delivery and where the customer guarantees a minimum of 4,000 annual hours' use of the actual demand. The Company will determine the particular nature of the voltage in each case. The customer shall furnish, install, own and maintain all equipment comprising the metered lighting system including, but not limited to, controls, protective equipment, transformers and overhead or underground metered lighting circuits extending to the point of attachment with the Company's distribution system. The Company shall furnish, install, own and maintain the metering equipment and connect the customer's metered lighting circuit to its distribution system and supply the energy for operation of the customer's metered lighting system.

Monthly Rate

Secondary Power Supply Charge

Energy Charge:

Non-Capacity	Capacity	Total	
$~~0.051003~~ *0.051457*	$0.000000	$~~0.051003~~ *0.051457*	per kWh for all kWh

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-4.00.

(Continued on Sheet No. D-47.00)

GENERAL SERVICE METERED LIGHTING RATE GML

(Continued From Sheet No. D-46.00)

Monthly Rate (Contd)

Secondary Delivery Charge

System Access Charge: $10.00 per customer per month

Distribution Charge: $~~0.065287~~ 0.062025 per kWh for all kWh

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-3.10 and the Power Plant Securitization Charges shown on Sheet No. D-5.10.

Primary Power Supply Charge

Energy Charge:

Non-Capacity	Capacity	Total	
$~~0.025030~~ 0.025253	$0.000000	$~~0.025030~~ 0.025253	per kWh for all kWh

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-4.00.

Primary Delivery Charge

System Access Charge: $20.00 per customer per month

Distribution Charge: $~~0.049394~~ 0.047268 per kWh for all kWh

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-3.10 and the Power Plant Securitization Charges shown on Sheet No. D-5.10.

Net Metering Program

The Net Metering Program is available to any eligible customer as described in Rule C11., Net Metering Program, who desires to generate a portion or all of their own retail electricity requirements using a Renewable Energy Resource as defined in Rule C11.B, Net Metering Program.

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

Green Generation Program

Customer contracts for participation in the Green Generation Program shall be available to any eligible customer as described in Rule C10.2, Green Generation Program.

A customer who participates in the Green Generation Program is subject to the provisions contained in Rule C10.2, Green Generation Program.

(Continued on Sheet No. D-48.00)

Attachment 2
To Settlement Agreement In Case No. U-20134

GENERAL SERVICE UNMETERED LIGHTING RATE GUL

(Continued From Sheet No. D-50.10)

Monthly Rate

The charge per luminaire per month shall be:

				Nominal Rating of Lamps (One Lamp per Luminaire) [1]			
				Service Charge per Luminaire [4]			
Type of Luminaire	**Watts**	**Watts Including Ballast [2]**	**Lumens**	**Capacity**	**Non-Capacity**	**Total**	**Fixture Charge per Luminaire [4]**
Mercury Vapor [3]	100	128	3,500	$~~7.76~~ 8.31	0.00	$~~7.76~~ 8.31	$6.00
Mercury Vapor [3]	175	209	7,500	~~12.67~~ 13.58	0.00	~~12.67~~ 13.58	6.00
Mercury Vapor [3]	250	281	10,000	~~17.03~~ 18.25	0.00	~~17.03~~ 18.25	6.00
Mercury Vapor [3]	400	458	20,000	~~27.76~~ 29.75	0.00	~~27.76~~ 29.75	6.00
Mercury Vapor [3]	700	770	35,000	~~46.67~~ 50.02	0.00	~~46.67~~ 50.02	6.00
Mercury Vapor [3]	1,000	1,080	50,000	~~65.46~~ 70.15	0.00	~~65.46~~ 70.15	6.00
High-Pressure Sodium [3]	70	83	5,000	~~5.03~~ 5.39	0.00	~~5.03~~ 5.39	6.00
High-Pressure Sodium	100	117	8,500	~~7.09~~ 7.60	0.00	~~7.09~~ 7.60	6.00
High-Pressure Sodium	150	171	14,000	~~10.36~~ 11.11	0.00	~~10.36~~ 11.11	6.00
High-Pressure Sodium [3]	200	247	20,000	~~14.97~~ 16.04	0.00	~~14.97~~ 16.04	6.00
High-Pressure Sodium	250	318	24,000	~~19.27~~ 20.66	0.00	~~19.27~~ 20.66	6.00
High-Pressure Sodium	400	480	45,000	~~29.09~~ 31.18	0.00	~~29.09~~ 31.18	6.00
Fluorescent [3]	380	470	20,000	~~28.48~~ 30.53	0.00	~~28.48~~ 30.53	6.00
Incandescent [3]	202	202	2,500	~~12.24~~ 13.12	0.00	~~12.24~~ 13.12	6.00
Incandescent [3]	305	305	4,000	~~18.48~~ 19.81	0.00	~~18.48~~ 19.81	6.00
Incandescent [3]	405	405	6,000	~~24.55~~ 26.31	0.00	~~24.55~~ 26.31	6.00
Incandescent [3]	690	690	10,000	~~41.82~~ 44.82	0.00	~~41.82~~ 44.82	6.00
Metal Halide	150	170	9,750	~~10.30~~ 11.04	0.00	~~10.30~~ 11.04	6.00
Metal Halide [3]	175	210	10,500	~~12.73~~ 13.64	0.00	~~12.73~~ 13.64	6.00
Metal Halide	250	290	15,500	~~17.58~~ 18.84	0.00	~~17.58~~ 18.84	6.00
Metal Halide	400	460	24,000	~~27.88~~ 29.88	0.00	~~27.88~~ 29.88	6.00

(1) Ratings for fluorescent lighting apply to all lamps in one luminaire.

(2) Watts including ballast used for monthly billing of the Power Supply Cost Recovery (PSCR) Factor, the Power Plant Securitization Charges and surcharges.

(3) Rates apply to existing luminaires only and are not open to new business.

(4) For customers who own their lighting fixtures and are assessed a Service Charge (but not a Fixture Charge), the charge per luminaire represents a ~~29.5~~ 26.9% Power Supply Charge and a ~~70.5~~ 73.1% Distribution Charge. For customers who do not own their lighting fixtures and are assessed both a Service Charge and a Fixture Charge, the charge per luminaire represents a ~~17.9~~ 17.2% Power Supply Charge and a ~~82.1~~ 82.8% Distribution Charge.

For energy conservation purposes, customers may, at their option, elect to have any or all luminaires served under this rate disconnected for a period of six months or more. The charge per luminaire per month, for each disconnected luminaire, shall be 40% of the monthly rate set forth above. However, should any such disconnected luminaire be reconnected at the customer's request after having been disconnected for less than six months, the monthly rate set forth above shall apply to the period of disconnection. An $8.00 per luminaire disconnect/reconnect charge shall be made at the time of disconnection except that when the estimated disconnect/reconnect cost is significantly higher than $8.00, the estimated cost per luminaire shall be charged.

For 24-hour mercury-vapor service, the charge per luminaire shall be 125% of the foregoing rates.

(Continued on Sheet No. D-52.00)

GENERAL UNMETERED EXPERIMENTAL LIGHTING RATE GU-XL

(Continued From Sheet No. D-54.01)

Facilities Policy (Contd)

Company-Owned Option (Contd)

D. The Company will determine the type and size of all experimental lighting fixtures to be offered under this rate. The list of approved fixtures is subject to modification at the sole discretion of the Company to accommodate new product development and advances in technology. Upon customer request, the Company shall provide a list of experimental lighting available under this rate.

E. The Company shall determine all associated equipment necessary to provide service under the Company-Owned Unmetered Experimental Lighting option.

F. Any charges, deposits or contributions may be required in advance of commencement of construction.

G. At the Company's discretion, any failed lighting fixtures may be converted to an equivalent LED at no cost to the customer if the customer agrees to the conversion. The replaced fixture will then be moved to General Unmetered Experimental Lighting Rate GU-XL upon completion of the installation.

Customer-Owned Option

If it is necessary for the Company to install distribution facilities to serve a customer-owned system, contributions and/or deposits for such additional facilities shall be calculated in accordance with the Company's general service line extension policy. Any charges, deposits or contributions may be required in advance of commencement of construction.

Monthly Rate

Power Supply Charges

Energy Charge:

Non-Capacity	Capacity	Total	
$~~0.059659~~ *0.048281*	$0.000000	$~~0.059659~~ *0.048281*	per kWh for all kWh

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-4.00.

Delivery Charges Customer-Owned Option

Distribution Charge:	$~~0.026842~~ *0.042193*	per kWh for all kWh

Delivery Charges Company-Owned Option

Distribution Charge:	$~~0.032923~~ *0.051752*	per kWh for all kWh
Fixture Charge per Luminaire:	$6.00	per month

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-3.10 and the Power Plant Securitization Charges shown on Sheet No. D-5.10.

General Terms

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

Due Date and Late Payment Charge

The due date of the customer bill shall be 21 days from the date of mailing. A late payment charge of 2% of the unpaid balance, net of taxes, shall be assessed to any bill which is not paid on or before the due date shown thereon.

Determination of Monthly Kilowatt-Hours and Burning Hours per Month Based on 4,200 Burning Hours per Year

The monthly kilowatt-hours shall be determined by multiplying the total capacity requirements in watts (including the lamps, ballasts, drivers, and control devices) times the monthly Burning Hours as defined below divided by 1,000. The customer shall not change the capacity requirements of the equipment owned by it without first notifying the Company in writing of such changes and the date that they shall be made, and modifying the lighting contract with the Company accordingly.

Jan	Feb	Mar	April	May	June	July	Aug	Sept	Oct	Nov	Dec	Total
457.8	382.2	369.6	306.6	264.6	226.8	252.0	298.2	336.0	399.0	432.6	474.6	4,200

Hours of Lighting

Unmetered Experimental Lighting shall be burning at all times when the natural general level of illumination is lower than about 3/4 footcandle, and under normal conditions this is approximately one-half hour after sunset until approximately one-half hour before sunrise. Lighting service will be supplied from dusk to dawn every night and all night on an operating schedule of approximately 4,200 hours per year.

(Continued on Sheet No. D-54.03)

GENERAL SERVICE UNMETERED RATE GU

Availability

Subject to any restrictions, this rate is available to the US Government, any political subdivision or agency of the State of Michigan, and any public or private school district for filament and/or gaseous discharge lamp installations maintained for traffic regulation or guidance, as distinguished from street illumination and police signal systems. Lighting for traffic regulation may use experimental lighting technology including light-emitting diode (LED). This rate is also available to Community Antenna Television Service Companies (CATV), Wireless Access Companies or Security Camera Companies for unmetered Power Supply Units. Where the Company's total investment to serve an individual location exceeds three times the annual revenue to be derived from such location, a contribution to the Company shall be required for the excess.

This rate is not available for resale purposes, new roadway lighting or for Retail Open Access Service.

Nature of Service

Customer furnishes and installs all fixtures, lamps, ballasts, controls, amplifiers and other equipment, including wiring to point of connection with Company's overhead or underground system, as directed by the Company. Company furnishes and installs, where required for center suspended overhead traffic light signals, messenger cable and supporting wood poles and also makes final connections to its lines. If, in the Company's opinion, the installation of wood poles for traffic lights is not practical, the customer shall furnish, install and maintain suitable supports other than wood poles. The customer shall maintain the equipment, including lamp renewals, and the Company shall supply the energy for the operation of the equipment. Conversion and/or relocation costs of existing facilities shall be paid for by the customer except when initiated by the Company.

The capacity requirements of the lamp(s), associated ballast(s) and control equipment for each luminaire shall be determined by the Company from the specifications furnished by the manufacturers of such equipment, provided that the Company shall have the right to test such capacity requirements from time to time. In the event that said tests shall show capacity requirements different from those indicated by the manufacturers' specifications, the capacity requirements shown by said tests shall control. The customer shall not change the capacity requirements of the equipment owned by it without first notifying the Company in writing of such changes and the date that they shall be made.

Monthly Rate

Power Supply Charges

Energy Charge:

Non-Capacity	Capacity	Total	
$~~0.056212~~ *0.055846*	$~~0.018227~~ *0.020186*	$~~0.074439~~ *0.076032*	per kWh for all kWh

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-4.00.

Delivery Charges

System Access Charge:	$2.00	per customer per month
Distribution Charge:	$~~0.017046~~ *0.017235*	per kWh for all kWh

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-3.10 and the *Power Plant* Securitization Charges shown on Sheet No. D-5.10.

(Continued on Sheet No. D-55.00)

(Continued From Sheet No. E-5.00)

E2. ROA CUSTOMER SECTION

E2.1 Terms and Conditions of Service

The ROA Service Standards and Rate Schedules set forth the rates, charges, terms and conditions of service for the delivery of Power to a ROA Customer, procured by a Retailer. Such Power shall be initially received at a designated Point of Receipt and ultimately delivered to the ROA Customer's Point of Delivery through the Company's Distribution System.

A customer's eligibility to take ROA Service is subject to the full satisfaction of any terms or conditions imposed by pre-existing contracts or tariffs with the Company.

A ROA Customer will specify only one Retailer at any given time for the supply of Power to each ROA Customer Account or ROA Customer location.

A ROA Customer shall be permitted to change Retailers. The changes will become effective at the completion of their normal billing cycle. A ROA Customer will be assessed a ROA Customer Switching Service Charge (as provided for in the ROA Rate Schedule) per account for each change. The change will be submitted to the Company electronically by the ROA Customer's Retailer as a new enrollment. The Company will notify the ROA Customer’s previous Retailer and new Retailer electronically of the effective date of the switch.

Upon receipt of the enrollment form from the customer's Retailer, the Company shall provide a new Retail Open Access Residential Secondary Rate ROA-R Customer with a pending enrollment with a Retailer a fourteen-day notice period (beginning with the day the Company receives the enrollment from the Retailer) in which the ROA-R Customer may cancel the enrollment before the switch is executed. A Retail Open Access Secondary Rate ROA-S and Retail Open Access Primary Rate ROA-P Customer's right to cancel an enrollment shall be in accordance with the terms of their contract with their Retailer.

A ROA Service Contract may be required in compliance with the Term and Form of Contract provision of the applicable ROA Rate Schedule. Termination of ROA Service for distribution services can be initiated by the ROA Customer in accordance with the written notice and the minimum term of ROA service requirements as provided for in the "Return to Company Full Service" provision in this ROA Customer Section or initiated by the Company with a minimum of 60 days' written notice.

E2.2 Metering

All load served under this tariff shall be separately metered. A ROA Customer receiving electric service with a Maximum Demand of 20 kW or more shall be metered *with a Wireless Under Glass Meter or be* required to install an Interval Data Meter.

A ROA Customer receiving electric service through Company-owned transformation will have varying metering requirements, depending on the ROA Customer's size. The metering requirements for these ROA Customers shall be determined as follows:

ROA Customer Maximum Demand	Required Metering
Less than 20 kW	*Wireless Under Glass Meter,* Energy-Only Registering Meter or Energy and Maximum
20 kW or Greater	*Wireless Under Glass Meter,* Demand Registering Meter Interval Data Meter

(Continued on Sheet No. E-7.00)

(Continued From Sheet No. E-6.00)

E2. ROA CUSTOMER SECTION (Contd)

E2.2 Metering (Contd)

Metering equipment for a ROA Customer shall be furnished, installed, read, maintained and owned by the Company.

For a ROA Customer with an Interval Data Meter *that is not a Wireless Under Glass Meter*, meter reading will be accomplished electronically through a ROA Customer-provided telephone line or other communication links that allow access to the meter data by the Company and are compatible with the Company's metering and billing systems. The communication link must be installed and operating prior to the ROA Customer receiving ROA Service.

A ROA load-profiled customer with maximum demand of 20 kW or less may receive meter reads by conventional means. If the load-profiled account exceeds a maximum demand of 20 kW *and the customer does not have a Wireless Under Glass Meter*, the customer will be required to install a communication line to access the Interval Data Meter electronically in order to continue ROA service if the customer is located in an area where electric Advanced Metering Infrastructure (AMI) transmitting technology meters are not available.

The ROA Customer*, not being metered with a Wireless Under Glass meter* shall obtain a separate telephone line for such purposes paying all charges in connection therewith. The ROA Customer is responsible for assuring the performance of the telephone line or other communication links at the time of meter interrogation for billing purposes. If the Company is unable to access meter data electronically, the Company will retrieve the data manually. If the Company is unable to access meter data electronically for two or more billing months within a 12 month period, the Company will assess a $45 charge for the second and all subsequent manual meter reads unless the inability to access the meter data electronically is the fault of the Company. The ROA Customer will be notified of the $45 manual meter read policy following the first incident requiring a manual meter read within the 12 month period. In the event that the Company is unable to access meter data electronically for three consecutive months, the ROA Customer's ROA Service shall be terminated and the ROA Customer shall be transferred to Company Full Service and be subject to the "Return to Company Full Service" provision unless telephonic access failure is due to non-performance of the telecommunications service provider or the Company. The 60-day notice requirement to terminate the ROA Customer's service does not apply in the event the Company is unable to access the ROA Customer's meter data electronically for three consecutive months and is subsequently returned to Company Full Service. In the event the Company is unable to access the meter data electronically for 12 consecutive months due to non-performance of the telecommunications service provider, the customer will be returned to full service. It is the customer's responsibility to notify the Company the status of any known telephonic communication issues that may inhibit the Company's ability to access meter data electronically.

A hardship exception may be made for cases where installation of both land-line and cellular telephone service is impractical *and a Wireless Under Glass Meter in not an option*. The burden of proving hardship rests on the customer. If the hardship exception is granted, the customer's meter will be manually read once a month, on a date the Company selects, for an additional charge of $45 month.

For *a Wireless Under Glass*, an Energy-Only Registering or Energy and Maximum Demand Registering metered ROA Customer, the meter will be read by conventional means and the ROA Customer will not be required to provide a telephone service or other communication link.

E2.3 Character of Service

A. Refer to the "Nature of Service" provision of the applicable ROA Rate Schedule.

B. The ROA Customer with a monthly-Maximum Demand greater than or equal to 1,000 kW is not required to utilize an Aggregator.

(Continued on Sheet No. E-8.00)

(Continued From Sheet No. E-19.00)

E3. RETAILER SECTION (Contd)

E3.7 Load Profiling

Retailers with ROA Customers who do not have an Interval Data Meter *or a Wireless Under Glass Meter* shall comply with the following provisions:

A. The Company will provide the Retailer with the rate class profile and applicable loss factor for the Retailer's customers as a basis for scheduling energy with MISO and reporting energy to MISO. The rate class profile will be the most recent profile approved for the Company by the MPSC.

B. Hourly Energy Reporting:

The Retailer or entity serving as the MDMA for the Retailer will report the hourly energy usage determined in (1) below to the MISO as the actual usage for the Retailer in the MISO energy market.

Hourly energy usage for MISO settlement shall be determined as follows:

(1) The Power consumed by the Retailer's ROA Customers shall be determined as the total of (a) and (b) as follows:

(a) For customers with Interval Data Meters *or Wireless Under Glass Meters*, by actual hourly energy usage, adjusted for losses.

(b) For customers with Energy-Only Registering Meters or Energy and Demand Registering Meters, hourly usage data for these customers will be determined by the use of the profile for the customer class to distribute the total weather adjusted usage (actual or estimated) in the billing period across all the hours in that billing period, adjusted for losses.

E3.8 Customer Protections

The maximum early termination fee for residential contracts of one year or less shall not exceed $50. The maximum early termination fee for residential contracts of longer than one year shall not exceed $100. It is the Retailer's responsibility to have a current valid contract with the customer at all times. Any contract that is not signed by the customer or Legally Authorized Person shall be considered null and void. Only the customer account holder or Legally Authorized Person shall be permitted to sign a contract. A Retailer and its agent shall make reasonable inquiries to confirm that the individual signing the contract is a Legally Authorized Person. For each customer, a Retailer must be able to demonstrate that a customer has made a knowing selection of the Retailer by at least one of the following verification records:

(1) An original signature from the customer account holder or Legally Authorized Person.
(2) Independent third party verification with an audio recording of the entire verification call.
(3) An e-mail address if signed up through the Internet.

The Commission or its Staff may request a reasonable number of records from a Retailer to verify compliance with this customer verification provision, and in addition, may request records for any customer due to a dispute.

A Retailer must distribute a confirmation letter to residential customers by U.S. mail. The confirmation letter must be postmarked within seven (7) days of the customer or Legally Authorized Person signing a contract with the Retailer. The confirmation letter must include the date the letter was sent, the date the contract was signed, the term of the contract with end date, the fixed or variable rate charged, the unconditional cancellation period, any early termination fee, the Retailer's phone number, the Commission's toll-free number and the Company's emergency contact information.

RETAIL OPEN ACCESS RESIDENTIAL SECONDARY RATE ROA-R

Availability:

Subject to any restrictions, this rate is available to any residential customer receiving service at Secondary Voltage for:

(i) delivery of Power from the Point of Receipt to the Point of Delivery,

(ii) any usual residential use as defined in Rule C4.3 A., Residential Usage and Rate Application,

(iii) single-phase or three-phase equipment, provided the individual capacity of such equipment does not exceed 3 hp or 3 kW, nor does the total connected load of the home exceed 10 kW, without the specific consent of the Company, and

(iv) service within Company designated service areas.

Service under this rate must be separately metered.

For those ROA Customers that do not have an Interval Data Meter *or a Wireless Under Glass Meter*, all Retailers shall assume that each Residential ROA Customer served under this rate has a Maximum Demand equivalent to 0.78 kW per hundred kWh of monthly use, using the month of maximum monthly consumption that occurred within the last 12 months.

Nature of Service:

Service under this rate shall be alternating current, 60-Hertz, single-phase or three-phase (at the Company's option) Secondary Voltage service. The Company will determine the particular nature of the voltage in each case.

The Company shall not be required to, but may expand its existing facilities to make deliveries under this tariff. The ROA Customer and/or Retailer shall be liable for any and all costs incurred as a result of an expansion of facilities made to make deliveries under this tariff.

Metering Requirements:

The load served under this tariff shall be separately metered by Energy-Only Registering Meters of billing quality *or a Wireless Under Glass Meter*. Such metering equipment shall be furnished, installed, maintained and owned by the Company.

The ROA Customer may elect an Interval Data Meter. Such metering equipment shall be furnished, installed, maintained and owned by the Company. The requesting ROA Customer shall be required to pay the System Access Charge in the Company Full Service General Service Secondary Rate GS for all such metering equipment.

The ROA Customer with an Interval Data Meter shall be responsible for (i) the communication links that allow access to the meter data by the Company and are compatible with the Company's metering and billing systems, and (ii) all associated costs relating to the communication links including other accompanying equipment and monthly fees.

(Continued on Sheet No. E-23.00)

RETAIL OPEN ACCESS RESIDENTIAL SECONDARY RATE ROA-R

(Continued From Sheet No. E-22.00)

RETAILER

Monthly Rate - Retailer:

Transmission Service:

Subject to Rule E1.5, Transmission Service must be obtained from the appropriate transmission service providers and the charges for such service shall be as specified in the Applicable FERC Open Access Tariff.

Real Power Losses:

The Retailer is responsible for replacing Real Power Losses of ~~7.239~~ *7.643*% on the Company's Distribution System associated with the movement of Power and for compensation for losses.

General Terms and Conditions:

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

Term and Form of Contract - Retailer:

All service under this rate shall require a written ROA Service Contract between the Company and a Retailer.

ROA CUSTOMER

Monthly Rate - ROA Customer:

ROA System Access Charge, Distribution Charge, General Terms, Minimum Charge and Due Date and Late Payment Charge:

The System Access Charge, Distribution Charge, General Terms, Minimum Charge and the Due Date and Late Payment Charge shall be as provided for under the ROA Customer's otherwise applicable Company Full Service rate.

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-3.10 and the Power Plant Securitization Charges shown on Sheet No. D-5.10. Customers taking ROA service on December 6, 2013 are excluded from the Power Plant Securitization Charges. This exclusion does not apply to customers first taking ROA service after December 6, 2013 or to customers taking service on December 6, 2013 who discontinue taking ROA service any time after December 6, 2013. Customers who discontinue taking ROA service any time after December 6, 2013 and who return to ROA service shall pay the Power Plant Securitization Charges applicable to the customer's otherwise applicable Company Full Service Rate Schedule.

State Reliability Mechanism for ROA:

Beginning June 1, 2018 all ROA customers may be subject to a State Reliability Mechanism Capacity Charge. This charge shall not apply to ROA customers for any planning year in which their Alternative Electric Supplier can demonstrate to the Commission that it can meet its capacity obligations by the seventh business day of February each year starting in 2018.

If a capacity charge is required to be paid in the planning year beginning June 1, 2018, or any of the three subsequent planning years, due to the Alternative Electric Supplier not meeting its capacity obligations, then the capacity charge is applicable for each of those planning years. Any capacity charged required to be paid any time after the first initial four-year period shall be applicable for a single year. The planning year is defined as being June 1 through the following May 31 of each year. The capacity charge paid by ROA customers will be the same amount as a Full Service Customer on the otherwise applicable Rate Schedule. Non-capacity charges shall not apply.

ROA Customer Switching Service Charge:

A $5.00 switching fee shall be charged the ROA Customer each time a ROA Customer switches (i) from one Retailer to another or (ii) from ROA to a Company Full Service rate. The ROA Customer may switch Retailers at the end of any billing month by having their new Retailer give the Company at least 30 days' written notice. The Company will notify the ROA Customer's previous Retailer and new Retailer electronically of the effective date of the switch. The ROA Customer may choose to return to Company Full Service at the end of any billing month in compliance with Rule

E2.5 D., Return to Company Full Service - Residential ROA Customers. The ROA Customer Switching Service Charge shall not be applied (i) for the initial switch to ROA Service or (ii) at the time the ROA Customer returns to Company Full Service or another Retailer because the ROA Customer was Slammed by the Retailer.

Term and Form of Contract - ROA Customer:

Service under this rate shall not require a ROA Service Contract between the Company and a ROA Customer.

RETAIL OPEN ACCESS SECONDARY RATE ROA-S

Availability:

Subject to any restrictions, this rate is available to any Non-Residential customer receiving Secondary Service for:

(i) delivery of Power from the Point of Receipt to the Point of Delivery,

(ii) service within Company designated service areas, and

(iii) resale service in accordance with Rule C4.4, Resale.

This rate is also available to a ROA-P Customer where the Company elects to provide one transformation from the available Primary Voltage to another available Primary Voltage desired by the customer.

Service under this rate must be separately metered.

For those ROA Customers that do not have an Interval Data Meter *or a Wireless Under Glass Meter*, all Retailers shall assume that each Secondary ROA Customer served under this rate has a Maximum Demand equivalent to 0.70 kW per hundred kWh of monthly use, using the month of maximum monthly consumption that occurred within the last 12 months.

This rate is not available for unmetered general service or for any unmetered or metered lighting service.

Nature of Service:

Service under this rate shall be alternating current, 60-Hertz, single-phase or three phase (at the Company's option) Secondary Voltage service. The Company will determine the particular nature of the voltage in each case.

When the service is three-phase, 3-wire, lighting may be included, provided the ROA Customer furnishes all transformation facilities required for such purpose, and so arranges the lighting circuits as to avoid excessive unbalance of the three-phase load. Service for the individual capacity of single-phase or three-phase equipment shall not exceed 3 hp or 3 kW, nor does the total connected load exceed 10 kW, without the specific consent of the Company.

The Company shall not be required to, but may expand its existing facilities to make deliveries under this tariff. The ROA Customer and/or Retailer shall be liable for any and all costs incurred as a result of an expansion of facilities made to make deliveries under this tariff.

(Continued on Sheet No. E-25.00)

RETAIL OPEN ACCESS SECONDARY RATE ROA-S

(Continued From Sheet No. E-24.00)

Metering Requirements:

The ROA Customer with a Maximum Demand of less than 20 kW shall be separately metered by *a Wireless Under Glass Meter or* an Energy Registering Meter, with or without maximum demand registers, of billing quality. Such metering equipment shall be furnished, installed, maintained and owned by the Company.

The ROA Customer with a Maximum Demand of less than 20 kW may elect to install an Interval Data Meter. Such metering equipment shall be furnished, installed, maintained and owned by the Company. The requesting ROA Customer shall be required to pay the System Access Charge, as provided for under the ROA Customer's otherwise applicable Company Full Service rate, for all such metering equipment.

The ROA Customer with a Maximum Demand of 20 kW or more shall be separately metered by *a Wireless Under Glass Meter or* an Interval Data Meter of billing quality. Such metering equipment shall be furnished, installed, maintained and owned by the Company. The ROA Customer shall be required to pay the System Access Charge, as provided for under the ROA Customer's otherwise applicable Company Full Service rate, for all such metering equipment.

The ROA Customer with an Interval Data Meter shall be responsible for (i) the communication links that allow access to the meter data by the Company and are compatible with the Company's metering and billing systems, and (ii) all associated costs relating to the communication links including other accompanying equipment and monthly fees.

RETAILER:

Monthly Rate - Retailer:

Transmission Service:

Subject to Rule E1.5, Transmission Service must be obtained from the appropriate transmission service providers and the charges for such service shall be as specified in the Applicable FERC Open Access Tariff.

Real Power Losses:

The Retailer is responsible for replacing Real Power Losses of ~~7.239~~ *7.643*% on the Company's Distribution System associated with the movement of Power and for compensation for losses.

General Terms and Conditions:

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

Term and Form of Contract - Retailer:

All service under this rate shall require a written ROA Service Contract between the Company and a Retailer.

(Continued on Sheet No. E-26.00)

RETAIL OPEN ACCESS PRIMARY RATE ROA-P

Availability:

Subject to any restrictions, this rate is available to any customer receiving service at a Primary Voltage for the delivery of Power from the Point of Receipt to the Point of Delivery and for resale service in accordance with Rule C4.4, Resale.

This rate is not available to a ROA-P Customer where the Company elects to provide one transformation from the available Primary Voltage to another available Primary Voltage desired by the customer. This ROA Customer must take service under Retail Open Access Secondary Rate ROA-S.

This rate is not available for unmetered general service or for any unmetered or metered lighting service.

Service under this rate shall be separately metered. The Retailer shall deliver a flat, fixed amount of power every hour of every day.

Any ROA Customer whose monthly minimum Maximum Demand is less than 1,000 kW must utilize an Aggregator.

Nature of Service:

Service under this rate shall be alternating current, 60-Hertz, single-phase or three-phase (at the Company's option) Primary Voltage service. The Company will determine the particular nature of the voltage in each case.

The Company shall not be required to, but may expand its existing facilities to make deliveries under this tariff. The ROA Customer and/or Retailer shall be liable for any and all costs incurred as a result of an expansion of facilities made to make deliveries under this tariff.

Metering Requirements:

The load under this tariff shall be separately metered by *a Wireless Under Glass Meter or* an Interval Data Meter of billing quality. Such metering equipment shall be furnished, installed, maintained and owned by the Company. The ROA customer shall be required to pay the System Access Charge, as provided for under the ROA customer's otherwise applicable Company Full Service rate, for all such metering equipment.

The ROA Customer with an Interval Data Meter shall be responsible for (i) the communication links that allow access to the meter data by the Company and are compatible with the Company's metering and billing systems, and (ii) all associated costs relating to the communication links including other accompanying equipment and monthly fees.

RETAILER

Monthly Rate - Retailer:

Transmission Service:

Subject to Rule E1.5, Transmission Service must be obtained from the appropriate transmission service providers and the charges for such service shall be as specified in the Applicable FERC Open Access Tariff.

Real Power Losses:

The Retailer is responsible for replacing Real Power Losses as shown below on the Company's Distribution System associated with the movement of Power and for compensation for losses.

	Meter Point	
	High Side	Low Side
Customer Voltage Level 1	0.000%	~~0.690~~ *0.705*%
Customer Voltage Level 2	~~1.390~~ *1.271*%	~~2.480~~ *2.366*%
Customer Voltage Level 3	~~3.660~~ *3.221*%	~~7.900~~ *7.643*%

(Continued on Sheet No. E-28.00)

ATTACHMENT 3

The parties agree that the Commission should adopt the PowerMIDrive pilot program proposed by the Company, subject to the modifications or recommendations proposed by any party in direct testimony and agreed to by the Company in its rebuttal testimony and subject to those changes proposed by Staff in its initial brief.

- Consumers Energy will hold stakeholder meetings during the first half of 2019 to receive input on the program and provide updates on program design decisions (e.g. approved charger lists, rebate criteria, etc.). The Company will also hold annual stakeholder meetings in 2020, 2021 and 2022 to share program progress and receive input on potential future program adjustments. Parties shall not be precluded from participating in stakeholder meetings due to participation in the PowerMIDrive program.

- To ensure valuable lessons are learned from the PowerMIDrive pilot program, the Company shall strive to ensure the participation of multiple multiple-dwelling unit (MDU) sites in the Public Charging Component. In consultation with the stakeholder workgroup participants, the Company will consider programmatic modifications necessary to ensure meaningful participation from MDUs, including modifying rebate amounts, simplifying metering and/or billing arrangements, targeted outreach, and cross-promotion with existing energy efficiency programs that serve MDUs.

- Since there are currently a limited number of DCFCs in Michigan, the Company will work with site hosts to educate them about applicable electricity rates and EV benefits, including the importance of fuel cost savings, while site hosts retain the ability to set pricing that reflects on-site needs

- Modifications to the Program as outlined in initial testimony and agreed to by the Company are as follows:

  (1) Raise PowerMIDrive pilot cap to $10 million with limit of $7.5 million for pilot-related O&M and rebates, and set separate spending cap of $2.5 million on 'make-ready' new or modified service connection expenditures

  (2) Exclude utility investment in 'make-ready' new or modified service connections from rebate program

  (3) Amortize costs over five years instead of ten

  (4) Educate site hosts about applicable electricity rates and EV benefits, while site hosts retain ability to set pricing that reflects on-site needs

- Additions to the Program as outlined in initial testimony and agreed to by the Company are as follows:

  (1) Address upgradeability or 'future-proofing' of its investment during stakeholder workgroup, prior to committing capital to DCFC site hosts

  (2) File initial rebate schedule and revisions as necessary

  (3) File annual report, with technical conference prior to filing

  (4) Monitor uptake of rebates by MDUs and modify at annual review if performance is low

  (5) Require site hosts to report pricing for charging, and report to Commission and stakeholders at least annually

(6) Hold stakeholder meetings during the first half of 2019 and annually in 2020, 2021, and 2022

(7) Strive to ensure participation of multi-dwelling units (MDU), working with stakeholder workgroup to consider programmatic modifications

P R O O F   O F   S E R V I C E

STATE OF MICHIGAN)

Case No. U-20134

County of Ingham)

Brianna Brown being duly sworn, deposes and says that on January 9, 2019 A.D. she electronically notified the attached list of this **Commission Order via e-mail transmission**, to the persons as shown on the attached service list (Listserv Distribution List).

Brianna J. Brown

Brianna Brown

Subscribed and sworn to before me
this 9th day of January 2019.

Angela P. Sanderson

Angela P. Sanderson
Notary Public, Shiawassee County, Michigan
As acting in Eaton County
My Commission Expires: May 21, 2024

Service List for Case: U-20134

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